TRANSMISSION SYSTEM PLAN: INTRODUCTION

1. INTRODUCTION

Hydro One's Transmission System Plan reflects Hydro One's commitment to meet customers' needs, manage health, safety and environmental risks, contain costs, fulfill its compliance obligations and be responsible stewards of its assets, and it demonstrates alignment with the principles set out in the Board's *Renewed Regulatory Framework for Electricity*.

Hydro One expects the plan to result in several key outcomes for Hydro One and its customers:

- maintaining top quartile reliability by mitigating risk arising from asset deterioration;
- minimizing the long-term costs of maintaining the reliability of the transmission system;
- ensuring that compliance with the regulatory and reliability standards is maintained:
- improving current levels of customer satisfaction;
- driving towards an injury-free workplace: and
- sustainably managing the environmental footprint of operations.

To achieve these outcomes, the Transmission System Plan reflects a shift in the balance of capital investment towards sustainment capital, with a focus on lines investments. In Hydro One's previous transmission revenue requirement application for the 2015-2016 period, it had put forth a sustainment capital program that began to address the need for higher sustainment investments by focusing on stations assets in poor condition that were a significant driver of reliability performance. Since then, Hydro One has focused on developing an improved understanding and knowledge of the condition of its transmission system.

Hydro One has gained additional knowledge through the ongoing testing of critical assets and expansion of the scope of condition assessments, combined with information collected about the actual performance (including failures) of individual assets. Hydro One has also been developing a greater understanding of how equipment unavailability due to condition and demographics are a leading indicator of future reliability issues, contributing to higher reliability risk. As a result of these efforts, Hydro One is continuing to prioritize replacement of assets with a goal of maintaining top quartile reliability and reducing reliability risk on the system.

As a result of its recent efforts to invest in the sustainment of stations assets, Hydro One has made significant progress in stabilizing the reliability risk from its stations assets. However, lines assets have continued to deteriorate and are now contributing to a larger proportion of the system's reliability risk. Hydro One expects to transition to placing a greater emphasis on lines-related sustainment investments (beginning in 2018) while maintaining a prudent level of stations investment in order to continue to mitigate risk.

In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital work efficiently and the ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario. Due to the planned refurbishment of large nuclear power plants in 2021 and beyond, Hydro One anticipates greater constraints to outage scheduling in the future. As a result, it has paced sustainment work so that critical work to reduce risk on the system could be completed in the next five years to ensure that transmission assets are in service before expected outage constraints make work more difficult to complete.

Hydro One is sensitive to the impacts of its Transmission System Plan on its customers, and thus has taken steps to ensure a prudent approach to investment and continued alignment with principles of RRFE by:

- Ensuring that the investment plan reflects customer needs and preferences identified in the customer engagement process, is consistent with the feedback obtained from the various other customer consultations undertaken by the company, and is aligned with the company's responsibility to provide effective stewardship of its transmission system assets;
- Identifying specific opportunities (e.g., steel tower coatings) where the company can extend the useful life of its assets and mitigate higher capital spending requirements for asset replacements in the future;
- Actively driving cost reduction and improved productivity to help offset the customer rate impacts of the proposed investment plan; and
- Implementing a more stringent performance management system – to provide greater transparency to the OEB, to customers, and to Hydro One's management and to provide confidence that targeted work is completed in an efficient manner, while delivering the promised outcomes for Hydro One's customers.

2. THE TRANSMISSION SYSTEM PLAN: FRAMEWORK

This Transmission System Plan is organized into four parts. Part One provides profile information of Hydro One Transmission, specifically, its regulatory environment, asset and customer base, core values and business objectives, and operations. Part One is set out in Exhibit B1, Tab 1.

Part Two describes the planning process that produced the investment plan for 2017 to 2018 which underpins this Application. It details the customer engagement activities, regional planning activities, and asset and risk assessments that Hydro One conducted to develop a well-prioritized investment plan. Part Two is set out in Exhibit B1, Tab 2.

Part Three explains the capital investments in the Transmission System Plan, describing the spending patterns over the historical, bridge and test years. Part Three is set out in Exhibit B1, Tab 3.

Part Four describes the capital work execution strategy that Hydro One intends to employ when implementing these investments. Part Four is set out in Exhibit B1, Tab 4.

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HYDRO ONE TRANSMISSION BUSINESS OVERVIEW

1. INTRODUCTION

Hydro One Networks Inc. ("Hydro One") is licensed by the Ontario Energy Board (the "OEB" or the "Board") to own, operate and maintain transmission facilities in the Province of Ontario. Hydro One's transmission system is one of the largest in North America. Hydro One's transmission business ("Hydro One Transmission") accounts for approximately 96% of the revenue of all licensed transmitters in Ontario.

The purpose of the transmission system is to transmit electricity between supply points (such as transmission-connected generators, and also transmission delivery points where distribution connected generation are injecting into the transmission system) and delivery points connecting Local Distribution Companies ("LDCs") and end-use transmission customers. The transmission system also interconnects with transmission systems in neighbouring jurisdictions in Canada and the U.S. and enables electricity transactions with those jurisdictions.

This Exhibit provides background on Hydro One Transmission's electricity and regulatory environment, an overview of Hydro One Transmission's system, and the values and business objectives that inform Hydro One Transmission's operations.

2. ELECTRICITY INDUSTRY AND REGULATORY FRAMEWORK

2.1 Industry and Regulatory Environment in Ontario

In Ontario, the Ministry of Energy sets legislative and regulatory requirements through changes to the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* and promotes energy policy.

Under the *Ontario Energy Board Act, 1998*, the OEB sets transmission rates, issues codes and licences, and grants approval for construction of new transmission lines exceeding two kilometers in length. The OEB's Transmission System Code ("TSC") sets out the obligations of electricity transmitters with respect to their customers. Among other matters, the TSC addresses standards for the operation, maintenance, management and expansion of transmission systems. As required by the TSC, Hydro One has entered into connection agreements with each directly-connected transmission customer and commercial agreements with directly-connected load and generation customers to recover appropriate costs related to new or modified Hydro One-owned connection facilities.

The Independent Electricity System Operator ("IESO") administers the electricity market, directs the operation of the power system in Ontario, and monitors and enforces compliance with its market rules. The IESO-controlled grid[1] comprises the infrastructure for transmitting large volumes of electrical energy from major generation sources to major load centers. The IESO coordinates and oversees the operation and the use of Hydro One's transmission facilities by market participants seeking to buy or sell electricity on the IESO-controlled grid.

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[1] The "IESO-controlled grid" means the transmission systems with respect to which, pursuant to operating agreements, the IESO has authority to direct operations. *IESO Market Manuals*, Chapter 11.

In January 2015, the Ontario Power Authority ("OPA") merged with the IESO, continuing under the IESO's corporate name. The IESO continues to have the accountabilities of the former OPA, such as establishing new electricity supply contracts, setting provincial conservation and demand management targets, forecasting long-term demand/supply requirements, and identifying the need for new or upgraded bulk transmission facilities required to incorporate new generation, relieve transmission constraints and meet system load growth. With respect to the planning for regional transmission facilities, the IESO leads the integrated regional resource planning process and coordinates with transmitters who lead the regional infrastructure planning process. Further details on the regional planning process can be found in Exhibit B1, Tab 2, Schedule 3.

2.2 Reliability Framework in North America

The North American Electric Reliability Council[2] ("NERC") was established in the United States in 1968 in response to the 1965 blackout. NERC's mission is to ensure the reliability of the bulk power system in North America. To achieve this, among its many activities, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future transmission and generation adequacy; and offers education and certification programs to industry personnel. NERC is a non-profit organization that relies on the diverse and collective expertise of industry participants.

NERC works with eight regional entities to improve the reliability of the bulk power system, the Northeast Power Coordinating Council ("NPCC") being one of them. NPCC

[2] On January 1, 2007, the North American Electric Reliability Council became the North American Electric Reliability Corporation.

develops regional reliability standards, monitoring and enforcing their compliance, and coordinates regional system planning, design and operations, and assessments of reliability. Hydro One is a member of NPCC and is registered with NERC's compliance registry.

Following the 2003 Northeast Blackout, the U.S. *Energy Policy Act of 2005* authorized the creation of a self-regulatory Electricity Reliability Organization ("ERO") that would span North America, under the oversight of the Federal Energy Regulatory Commission ("FERC") in the U.S. The legislation stated that compliance with reliability standards would be mandatory and enforceable. In July 2006, FERC certified NERC as the ERO in the United States. In October 2006, the OEB signed a memorandum of understanding with NERC recognizing NERC as the ERO in Ontario.

According to the OEB's memorandum of understanding with NERC and the IESO's market rules, however, in Ontario only the IESO is directly subject to the Compliance Monitoring and Enforcing Program of NERC and NPCC.

The IESO's Market Assessment and Compliance Division, in turn, is responsible for monitoring and enforcing the reliability standards in Ontario.

Hydro One is subject to the planning and operating criteria and standards established by NPCC for the interconnected bulk power system in the northeast region. Hydro One participates with other transmission owners and system operators on NPCC committees and task forces to coordinate planning and operations in the northeast.

As a licensed transmitter, Hydro One is legally obligated to comply with the reliability standards adopted by NERC and NPCC.

On March 24, 2014, FERC approved NERC's submission of the new definition of the Bulk Electric System ("BES") effective July 1, 2014. This new definition significantly expands the scope of power system elements that are subject to NERC's reliability standards. The new BES definition includes all transmission facilities greater than 100 kV. The definition is also referred to as a "bright-line" definition because it is based on a defined voltage threshold of 100 kV. Prior to this, the BES definition captured only facilities in Ontario that have a material impact on the reliability of the bulk power system, regardless of the voltage level.

While the new BES definition does allow for some inclusions and exclusions, the vast majority of Ontario's transmission facilities greater than 100 kV will be subject to this definition. Further exclusions from the standard definition require applications under an exception process administered by the IESO on a case-by-case basis. Attachment 1 identifies Hydro One's key physical assets that are classified as BES. Hydro One has mitigated the impact of the costs of the changed BES definition on its business by seeking and obtaining reduced compliance requirements for 111 BES elements from the IESO that are not considered material to the bulk power system.

3. HYDRO ONE'S TRANSMISSION BUSINESS

3.1 Transmission System Overview

Hydro One Transmission's system is a high voltage system that operates at 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV and 69 kV. A simplified figure of the transmission system is provided in Figure 1 below. Detailed transmission system maps are provided in Attachment 2 to this Exhibit.

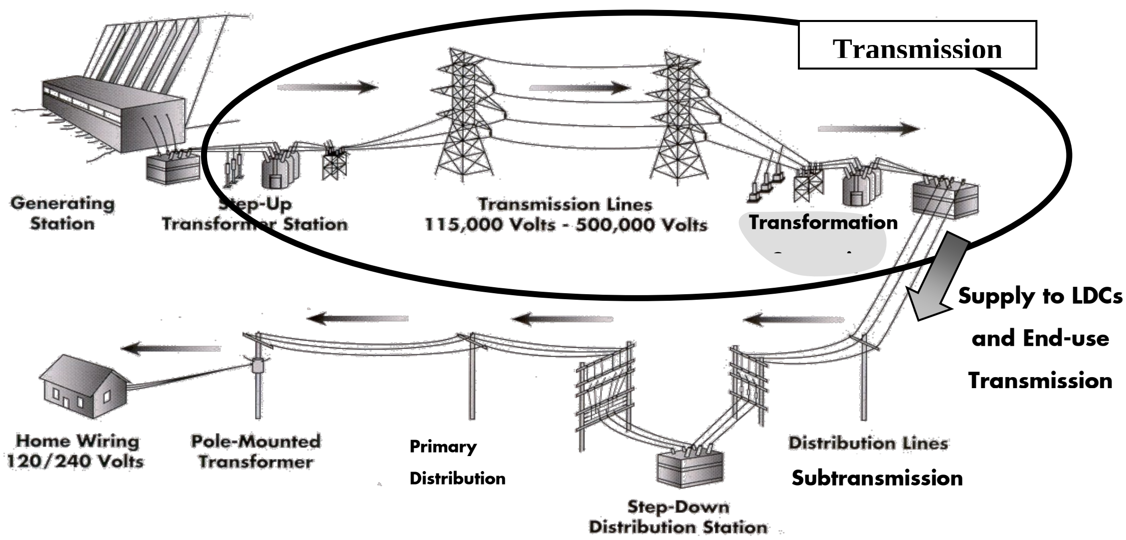

Figure 1: Hydro One Transmission's System [3]

In 2015, Hydro One transmitted approximately 137 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Hydro One Transmission serves a customer base composed of generators, large industrial end users and local distribution companies. Table 1 provides a profile of the customer base connected to Hydro One Transmission's system.

Table 1: Transmission-connected Customers (December 31, 2015)

Customer Type	Number Served
Generators	119
End Users (Large Industrial Customers)	90
Local Distribution Companies	47

Depending on the configuration and ownership of facilities, Hydro One Transmission generally provides customers with one or more of the following transmission services: network, line connection, transformation connection and wholesale meter services.

[3] For illustrative purposes only, actual configuration may vary from case to case and may include generators within LDCs and end-use transmission customer facilities.

The Hydro One Transmission system is comprised of high voltage transmission lines and transmission stations. Transmission lines and stations are located on lands owned by the Ontario government, Hydro One or other parties with whom Hydro One has agreements regarding occupancy and access rights. The major components of the transmission lines are overhead conductors, underground cables, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems. The major components of transmission stations are transformers, circuit breakers, switches, bus bars, insulators, reactors, capacitors, connecting hardware, associated protection and control equipment, grounding systems and revenue meters.

Transmission assets also include facilities required for operation, protection, control, and monitoring functions necessary for the effective and efficient operation of the transmission system. These facilities include extensive telecommunication system, protection and control equipment, the Ontario Grid Control Centre ("OGCC") and its back-up operating centre which enable it to monitor and control the operation of the transmission system.

Table 2: Hydro One Transmission System Assets
At December 31, 2015 *(unless where otherwise noted)*

Gross Fixed Assets	$15.0 Billion
Net Book Value Fixed Assets	$10.5 Billion
Operating Centres	2
Transmission System Voltages (kV)	500, 345, 230, 115, 69
Overhead Transmission Lines (circuit km)	29,080
Underground Transmission Cables (circuit km)	274
Transmission Stations[4]	292

The Hydro One Transmission system is linked to five adjoining jurisdictions (Manitoba, Quebec, Minnesota, Michigan and New York) through 26[5] interconnections, as shown in Figure 2. These interconnection facilities are designed to facilitate the transfer of electrical energy between Ontario and these jurisdictions. They can accommodate theoretical maximum imports of about 6580 MW and exports of approximately 6033[6] MW of electricity in the summer. Actual import and export capabilities of the interconnections depend on limitations at the interface as well as within Hydro One Transmission's system and transmission systems in other jurisdictions.

[4] Includes both transformer stations and switching stations.
[5] One interconnection no longer required by Ontario Power Generation or National Grid is expected to be decommissioned in the second quarter of 2016.
[6] From the IESO Ontario Transmission System report December 14, 2015.

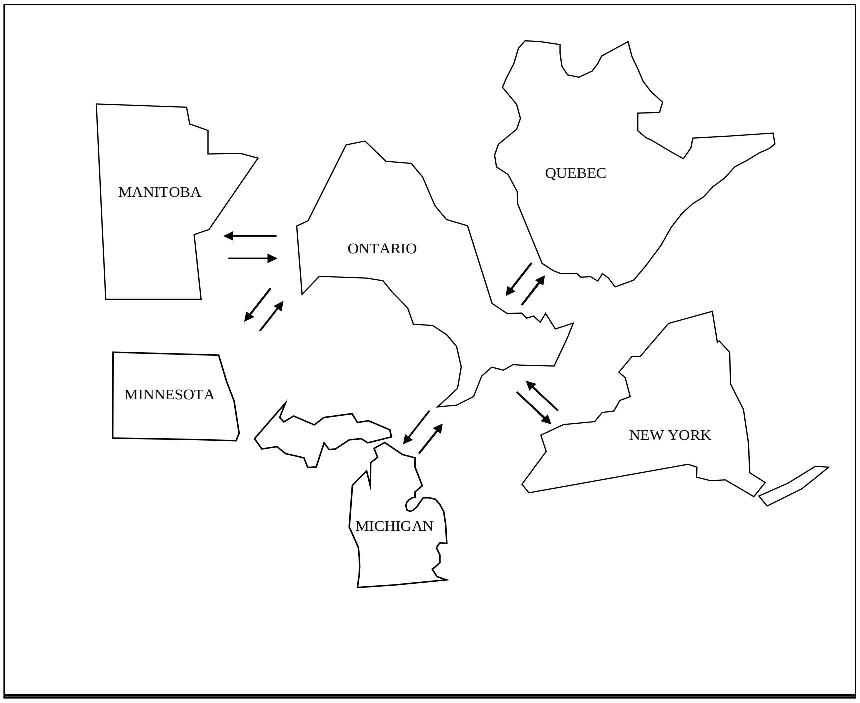

Figure 2: Existing Ontario Interconnections

Hydro One Transmission's system is also connected to other transmitters within Ontario, namely Great Lakes Power, Canadian Niagara Power, Five Nations Energy, and B2M Limited Partnership. These transmitters account for the remaining 4% of transmission revenue in Ontario.

3.2 Hydro One's Core Values and Business Objectives

Hydro One is guided by core values promoting: (1) a safe workplace for its employees and the public; (2) a customer caring environment; (3) one company working to meet customer, commercial and shareholder needs with integrity; (4) a people-powered business, committed to engaging, developing and retaining the best people; and (5) the pursuit of execution excellence in delivering safe, reliable, affordable transmission service. As a steward of assets that are critically important to customers and the provincial economy, Hydro One is committed to delivering the level of service required by customers, safely, in a manner that complies with regulatory requirements and that manages the company's environmental footprint. This is reflected in the company's business objectives set out in Table 3. These values and goals underpin and drive the operation and planning of Hydro One's business. They are also consistent with the outcomes promoted by the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-based Approach* ("RRFE").

Table 3: Transmission Business Objectives

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Maintain top quartile reliability relative to transmission peers
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB

3.3 Transmission Business Activities

Hydro One utilizes asset management processes in the planning, approval, and execution of work to make decisions involving customer and asset requirements. The primary process includes two key functions: defining the work requirements, and executing the asset and customer based services in accordance with the defined work requirements.

The asset management process ensures that asset-related decisions are consistent, cost-efficient and effective. These decisions are aimed at developing a prioritized and rationalized investment plan for the operation, maintenance, refurbishment, replacement and upgrade of existing assets, and the addition of new assets, as documented in Exhibit B1, Tab 2, Schedule 6. This prioritized plan is then detailed, scheduled and implemented by the work execution functions.

Hydro One continues to focus on ensuring, and being able to demonstrate, that the necessary assets are planned, acquired, constructed, maintained and operated to deliver the design function and level of reliability expected by customers in a sustainable manner in line with regulation.

To provide reliable, quality service to its customers, Hydro One's business activities focus on customer relations and system sustainment, expansion, and operations. Internally, and for the purposes of this Application, Hydro One refers to these activities (and associated investments) as "Sustainment", "Development", "Operations", "Common Corporate", and "Customer Care" activities.

3.4 Sustainment

Sustainment work involves investing in the existing infrastructure to enable equipment to continue to perform to its design standards, manage reliability risk and deliver the desired level of reliability system-wide, while meeting all legislative, regulatory, safety and environmental requirements. The OM&A component of Sustainment work addresses preventative and breakdown (corrective) including mid-life overhauls which are required to achieve the expected equipment's expected service life span. The capital component of the Sustainment work deals with replacement of assets which have reached their end of life. The Sustainment capital and OM&A components of the investment plan are described in Exhibit B1, Tab 3, Schedule 2 and Exhibit C1, Tab 2, Schedule 2, respectively.

3.4.1 Development

Development work is defined as work required to increase the capacity and capability of the transmission system by constructing additional transmission facilities or upgrading existing facilities. The Development capital and OM&A components of the investment plan are described in Exhibit B1, Tab 3, Schedule 3 and Exhibit C1, Tab 2, Schedule 3, respectively.

3.4.2 Operations

Operations investments focus on grid control centres and associated operating infrastructure, equipment and facilities that monitor and operate the transmission assets to ensure that power flows are within the capability of the transmission system, respond to contingencies, coordinate and schedule planned outages, execute switching operations to enable maintenance and construction and monitor and report on the performance of the transmission system.

Operating capital investments enhance, refurbish and replace transmission system computer management systems and data acquisition systems, including automatic system controls, which monitor and control the operation of the transmission system. OM&A expenditures maintain transmission system computer management systems and data acquisition systems, including automatic system controls, and fund the resources required to perform the activities necessary for centralized operation of the transmission system. The Operations capital and OM&A components of the investment plan are described in Exhibit B1, Tab 3, Schedule 4 and Exhibit C1, Tab 2, Schedule 4, respectively.

3.4.3 Common Corporate

Hydro One uses a centralized shared services model to support Hydro One Transmission and its affiliates. Common Corporate capital investments include shared land and buildings, telecommunications equipment, computer equipment, applications software, tools and transportation and work equipment. Common Corporate OM&A costs include the provision of common corporate functions and services, asset management planning services, information technology, cost of sales to external parties and other OM&A. The details of the Common Corporate capital and OM&A investments are described in Exhibit B1, Tab 3, Tab 5 and Exhibit C1, Tab 3, respectively.

3.4.4 Customer Care

The Customer Care function manages the relationship with customers who want to connect or are connected to the transmission system. This function facilitates communications between the customer and the responsible groups within Hydro One on matters such as customer connection requests, service and power quality enquiries or complaints, and the coordination of asset sustainment activities on both sides of the connection point. While customer billing is primarily handled by the IESO, the Customer Care function manages meter data aggregation, some billing, and settlement activities. For Hydro One, Customer Care activities are funded by OM&A expenditures only, described in Exhibit C1, Tab 2, Schedule 5.

ASSET LIST - BES DESIGNATION

Transformers

Bus or Station	ID	BES (NERC)
500kV/230kV		
BRUCE A	T28/T27/T25	Yes
CHERRYWOOD	T14/T17/T15/T16	Yes
CLAIREVILLE	T13/T14/T15/T16	Yes
ESSA	T3/T4	Yes
HANMER	T6/T7/T8/T9	Yes
HAWTHORNE	T1/T2/T3	Yes
LENNOX	T51/T52	Yes
LONGWOOD	T3/T4/T5/T6/T7	Yes
MIDDLEPORT 1	T3	Yes
MIDDLEPORT 2	T6	Yes
NANTICOKE	T11/T12	Yes
PARKWAY	T3/T4	Yes
PINARD	T1/T2	Yes
PORCUPINE	T7/T8	Yes
TRAFALGAR	T14/T15	Yes
500kV/115kV		
PORCUPINE	T3/T4	Yes
230kV/115kV		
ALGOMA	T5/T6	Yes
ALLANBURG	T1/T2/T3/T4	Yes
ANSONVILLE	T2	Yes
BEACH	T1/T7/T8	Yes
BUCHANAN	T2/T3/T4	Yes
BURLINGTON	T4/T6/T9/T12	Yes
CATARAQUI	T2/T1	Yes
CHENAUX	T4/T3	No
DES JOACHIMS	T7/T6* radial part	No
DETWEILER	T2/T3/T4	Yes
DOBBIN	T1/T2/T5	No

DRYDEN	T22/T23	Yes
DYMOND	T2/T1	Yes
ESSA	T1/T2	Yes
FORT FRANCES	T1/T2	Yes
HANOVER	T4/T3	No
HAWTHORNE	T4/T5/T6/T7	Yes
KEITH	T11/T12	Yes
KENORA	T1	Yes
LAKEHEAD	T7/T8	Yes
LAUZON	T1/T2	Yes
LEASIDE EAST, WEST	T11/12/14/15/16/17	Yes
MACKENZIE	T3	Yes
MANBY EAST	T7/T8/T9	Yes
MANBY WEST	T1/T2/T12	Yes
MARATHON	T11/T12	Yes
MARTINDALE	T21/T22/T23	Yes
MERIVALE	T21/T22	Yes
OTTO HOLDEN	T3/T4	Yes
OWEN SOUND	T5	No
PRESTON	T2	No
SCOTT	T6/T5	Yes
SEAFORTH	T5/T6	No
SPRUCE FALLS	T7	Yes
STAYNER	T1	No
ST LAWRENCE	T2/T3	Yes
WAWA	T1/T2	Yes
KARN TS	T1/T1	No
345kV/230kV		
LAMBTON	T7/T8	Yes
BECK 2	T301/T302	Yes

Phase Shifters/Regulators

LAMBTON	PS4/PS51	Yes
KEITH	PSR5	Yes
ST LAWRENCE	R33/PS33/PSR34	Yes
BECK 2	R27/R76	Yes

Station Service and Load Transformers connected to BPS Buses

Substation Name	Element designation	BES (NERC)
CHERRYWOOD	T7, T8	Yes
LAMBTON	T5, T6	Yes
BEACH	T5, T6	Yes
COOKSVILLE	T3, T4, T5, T6	Yes
HAWTHORNE	T7, T8	Yes
MANBY	T3, T4, T5, T6, T13, T14	Yes
NANTICOKE	T13	Yes
RICHVIEW	T1, T2, T7, T8	Yes

Reactive Resources > 100 kv

Bus or Station	kV	ID	BES (NERC)
ALGOMA	230	SC21	Yes
ALLANBURG	115	SC11	Yes
ALLANBURG	115	SC12	Yes
BIRCH	115	SC11	Yes
BUCHANAN TS	115	SC11	Yes
BUCHANAN TS	230	SC21	Yes
BUCHANAN TS	230	SC22	Yes
BUCHANAN TS	230	SC23	Yes
BURLINGTON	115	SC11	Yes
BURLINGTON	230	SC21	Yes
BURLINGTON	230	SC22	Yes
CHATHAM	230	SC21	Yes
CHATHAM	230	SC22	Yes
CHATHAM	230	SC23	Yes
DETWEILER	115	SC11	Yes

Bus or Station	**kV**	**ID**	**BES (NERC)**
DETWEILER	115	SC12	Yes
DETWEILER	230	SC21	Yes
DETWEILER	230	SC22	Yes
DYMOND	115	SC11	Yes
DYMOND	115	SC12	Yes
ESSA	230	SC21	Yes
ESSA	230	SC22	Yes
FORT FRANCES	115	SC1	Yes
FORT FRANCES	115	SC2	Yes
HANMER	230	SC21	Yes
HANMER	230	SC22	Yes
HANMER	500	R1	Yes
HANMER	500	R2	Yes
HAWTHORNE	115	SC11	Yes
HAWTHORNE	115	SC12	Yes
HAWTHORNE	230	SC22	Yes
HAWTHORNE	230	SC23	Yes
HEARN	115	SC11	Yes
HEARN	115	SC12	Yes
JOHN	115	SC11	Yes
KEITH	115	SC11	Yes
KIRKLAND LAKE	115	SC11	Yes
LAKEHEAD	115	SC11	Yes
LAUZON	115	SC12	Yes
LEASIDE EAST, WEST	115	SC13	Yes
LEASIDE EAST, WEST	115	SC11	Yes
LEASIDE EAST, WEST	115	SC14	Yes
LEASIDE EAST, WEST	115	SC12	Yes
LONGWOOD	230	SC21	Yes
LONGWOOD	230	SC22	Yes
LONGWOOD	230	SC25	Yes
LONGWOOD	230	SC26	Yes
MANBY EAST	230	SC22	Yes

Bus or Station	kV	ID	BES (NERC)
MANBY WEST	230	SC21	Yes
MERIVALE	115	SC11	Yes
MIDDLEPORT 1	230	SC21	Yes
MIDDLEPORT 1	230	SC22	Yes
MIDDLEPORT 2	230	SC23	Yes
MIDDLEPORT 2	230	SC24	Yes
MOOSONEE	115	R1	No, E4
MOOSONEE	115	R2	No, E4
NANTICOKE	230	SC21	Yes
NANTICOKE	230	SC22	Yes
ORANGEVILLE	230	SC21	Yes
PORCUPINE	230	SC21	Yes
PORCUPINE	230	SC22	Yes
RICHVIEW 1	230	SC22	Yes
RICHVIEW 2	230	SC21	Yes
TRAFALGAR	230	SC21	Yes

Reactive Resources - Autos

Bus or Station	kV	ID	BES (NERC)
BRUCE A	27.6	R25	Yes
BRUCE A	27.6	R27	Yes
BRUCE A	27.6	R28	Yes
ESSA	27.6	R3	Yes
ESSA	27.6	R4	Yes
FORT FRANCES	13.2	R2	Yes
FORT FRANCES	13.2	SC3	Yes
HANMER	27.6	R6	Yes
HANMER	27.6	R7	Yes
HANMER	27.6	R8	Yes
HANMER	27.6	R9	Yes
HAWTHORNE	27.6	R2	Yes
HAWTHORNE	27.6	R3	Yes

Bus or Station	kV	ID	BES (NERC)
KENORA	13.8	R1	Yes
LENNOX	27.6	R51	Yes
LENNOX	27.6	R52	Yes
LONGWOOD	27.6	R3	Yes
LONGWOOD	27.6	R4	Yes
LONGWOOD	27.6	R5	Yes
LONGWOOD	27.6	R6	Yes
LONGWOOD	27.6	R7	Yes
MACKENZIE	13.8	R3	Yes
MARATHON	13.8	SC29	Yes
MARATHON	13.8	SC21	Yes
MARATHON	13.8	R11	Yes
MARATHON	13.8	R12	Yes
PINARD	27.6	R1	Yes
PINARD	27.6	R2	Yes
WAWA	13.8	R1	Yes
WAWA	13.8	SC1	Yes
WAWA	13.8	R2	Yes
WAWA	13.8	SC2	Yes

Reactive Resources - SVCs

Bus or Station	ID	kV	BES (NERC)
DETWEILER	SVC1	22.5	Yes
KIRKLAND LAKE	SVC1	15	Yes
LAKEHEAD	SVC1	13.8	Yes
NANTICOKE	SVC1	16.5	Yes
PORCUPINE	SVC1	19.65	Yes

Lines

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
RABBIT LAKE SS			115	No
IGNACE JCT			115	No
NIPIGON JCT			115	No
RESERVE JCT			115	No
SEAFORTH	CONSTANCE		115	No
GAMBLE H9A JCT			115	No
AGUASABON	TERRACE BAY		115	Yes
HAWTHORNE			115	No
MACKENZIE	LAKEHEAD		230	Yes
MACKENZIE	LAKEHEAD		230	Yes
ALGOMA	MISSISSAGI		230	Yes
ALGOMA	MISSISSAGI		230	Yes
ALLANBURG	MURRAY		115	Yes
ALLANBURG	MURRAY		115	Yes
MACKENZIE	MOOSE LAKE		115	Yes
HAWTHORNE	RIVERDALE	MERIVALE	115	Yes
HAWTHORNE	PQ - OUTAOUAIS		230	Yes
HAWTHORNE	PQ - OUTAOUAIS		230	Yes
ANSONVILLE	HUNTA		115	Yes
HAWTHORNE	OVERBROOK		115	Yes
ALEXANDER SS	LONG LAC		115	Yes
MACKENZIE				No
ALEXANDER SS	AGUASABON		115	Yes
ANSONVILLE	HUNTA		115	Yes
HAWTHORNE	RIVERDALE	KING EDWARD	115	Yes
ALLANBURG	CROWLAND		115	No
ALEXANDER SS	PORT ARTHUR		115	Yes
HAWTHORNE	RIVERDALE		115	Yes
ALLANBURG	CROWLAND		115	No
ALEXANDER SS	LAKEHEAD		115	Yes
ALLANBURG			115	No
ANSONVILLE	KIRKLAND LAKE		115	Yes

Witness: Mike Penstone

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
ALEXANDER SS	LAKEHEAD		115	Yes
HAWTHORNE	MERIVALE		115	Yes
ANSONVILLE	KIRKLAND LAKE		115	Yes
BEACH			115	No
BURLINGTON			115	No
BURLINGTON			115	No
BURLINGTON			115	No
BURLINGTON			115	No
COOKSVILLE			230	Yes
COOKSVILLE			230	Yes
BURLINGTON	HAMILTON BEACH		230	Yes
BARRETT CHUTE	SIDNEY		115	No
BURLINGTON	HAMILTON BEACH		230	Yes
BRUCE A	DOUGLAS POINT		230	Yes
BRUCE A	DETWEILER		230	Yes
BELLEVILLE	CHERRYWOOD SOUTH		230	Yes
BRUCE A	DETWEILER		230	Yes
BRUCE A	DOUGLAS POINT		230	Yes
BRUCE A	OWEN SOUND		230	Yes
BRUCE A	OWEN SOUND		230	Yes
BURLINGTON			115	No
PQ - BEAUHARNOIS	ST LAWRENCE		230	Yes
BLIND RIVER	ELLIOT LAKE		115	No
MI - BUNCE CREEK	SCOTT		230	Yes
BURLINGTON			115	No
BURLINGTON	CUMBERLAND		230	Yes
BURLINGTON	CUMBERLAND		230	Yes
ALGOMA	BLIND RIVER		115	No
BLIND RIVER	ELLIOT LAKE		115	No

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
BRUCE A	ORANGEVILLE		230	Yes
BRUCE B	MILTON		500	Yes
BRUCE A	MILTON		500	Yes
DARLINGTON	CHERRYWOOD		500	Yes
DARLINGTON	CHERRYWOOD		500	Yes
DARLINGTON	CHERRYWOOD		500	Yes
DARLINGTON	CHERRYWOOD		500	Yes
BRUCE A	CLAIREVILLE		500	Yes
BRUCE B	MILTON		500	Yes
BRUCE A	EVERGREEN		500	Yes
EVERGREEN	LONGWOOD		500	Yes
EVERGREEN	PARKHILL		500	Yes
BRUCE B	ASHFIELD		500	Yes
ASHFIELD	LONGWOOD		500	Yes
ASHFIELD	K2 Wind		500	Yes
BRUCE A	BRUCE B		500	Yes
BEAUHARNOIS	ST ISODORE		230	Yes
BURLINGTON	CEDAR		115	No
BARRETT CHUTE	CATARAQUI		115	Yes
RAILTON JCT	FRONTENAC		115	No
BRUCE A	ORANGEVILLE		230	Yes
BURLINGTON	CEDAR		115	No
BIRCH	MOOSE LAKE		115	Yes
BURLINGTON			115	No
BURLINGTON			115	No
BRUCE A	BRUCE HEAVY WATER B		230	Yes
BRUCE A	BRUCE HEAVY WATER B		230	Yes
BROWN HILL	CLAIREVILLE		230	Yes
BROWN HILL	CLAIREVILLE		230	Yes
BRANT	WOODSTOCK		115	No
BECK 1			115	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
BECK 2	NY PACKARD		230	Yes
Beck #1			115	No
CHERRYWOOD NORTH	AGINCOURT		230	Yes
CALEDONIA			115	No
CHERRYWOOD NORTH	LEASIDE		230	Yes
CHERRYWOOD SOUTH	LEASIDE		230	Yes
CHERRYWOOD SOUTH	LEASIDE		230	Yes
CHERRYWOOD SOUTH	LEASIDE		230	Yes
CHERRYWOOD NORTH	RICHVIEW		230	Yes
ALEXANDER SS			115	Yes
CROWLAND	PORT COLBORNE		115	No
CHERRYWOOD NORTH	RICHVIEW		230	Yes
CHATHAM	KEITH		230	Yes
CHATHAM	KEITH		230	Yes
CHATHAM	LAUZON		230	Yes
CHATHAM	LAUZON		230	Yes
CHATS FALLS	HAVELOCK		230	Yes
CHATS FALLS	DOBBIN		230	Yes
CHERRYWOOD SOUTH	CHATS FALLS		230	Yes
CAMERON FALLS	ALEXANDER SS		115	Yes
CANYON	HUNTA		115	Yes
LEASIDE	CHERRYWOOD NORTH		230	Yes
CROWLAND	PORT COLBORNE		115	No
Chatham	SOUTH KENT GS		230	Yes
CHERRYWOOD NORTH	PARKWAY		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
CHERRYWOOD SOUTH	PARKWAY		230	Yes
CAMERON FALLS	ALEXANDER SS		115	Yes
CHERRYWOOD NORTH	LEASIDE		230	Yes
CHATS FALLS	SOUTH MARCH		230	Yes
CHERRYWOOD SOUTH	RICHVIEW		230	Yes
CLAIREVILLE	CHERRYWOOD	PARKWAY	500	Yes
CLAIREVILLE	CHERRYWOOD		500	Yes
CLAIREVILLE	CHERRYWOOD		500	Yes
CLAIREVILLE	CHERRYWOOD	PARKWAY	500	Yes
CECIL	ESPLANADE		115	No
CHERRYWOOD SOUTH	RICHVIEW		230	Yes
CHATS FALLS	BARRETT CHUTE	MERIVALE	115	Yes
CECIL	ESPLANADE		115	No
CALEDONIA			115	No
DETWEILER	HANOVER		115	No
DECEW FALLS	GLENDALE		115	No
DETWEILER	KITCHENER		115	No
DETWEILER	KITCHENER		115	No
DECEW FALLS	ALLANBURG		115	Yes
DESJOACHIMS	MINDEN		230	Yes
DETWEILER	WOLVERTON		115	No
PINARD	DETOUR LAKE MINE		230	No
DRYDEN	MACKENZIE		230	Yes
DYMOND	CRYSTAL FALLS		115	Yes
DESJOACHIMS	MINDEN		230	Yes
DECEW FALLS	ALLANBURG		115	Yes
PINARD	HUNTA		115	Yes
KIRKLAND LAKE	DYMOND		115	Yes
DESJOACHIMS	MINDEN		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
DESJOACHIMS	MINDEN		230	Yes
DETWEILER	BUCHANAN		230	Yes
DYMOND	RAPID DES ISLE		115	No
PINARD	PORCUPINE		500	Yes
ST ISIDORE	HAWTHORNE	PQ - MASSON	230	Yes
DRYDEN	DRYDEN WEYERHAEUSER		115	No
DESJOACHIMS	HOLDEN		230	Yes
DETWEILER	BUCHANAN		230	Yes
DESJOACHIMS			115	No
PINARD	OTTER RAPIDS		115	No
DETWEILER	ORANGEVILLE		230	Yes
DUPLEX	GLENGROVE		115	No
DETWEILER	FREEMONT		115	No
DETWEILER	ORANGEVILLE		230	Yes
DETWEILER	ST MARY		115	No
DETWEILER	FREEMONT		115	No
DECEW FALLS	GLENDALE		115	No
EAR FALLS	CROW RIVER		115	No
ESSA	STAYNER		230	Yes
ESSA	STAYNER		230	Yes
ESSA			230	Yes
ESSA			230	Yes
EAR FALLS	RED LAKE		115	No
ESSA	BARRIE		115	No
ESSA	BARRIE		115	No
EARFALLS	DRYDEN		115	Yes
ESSA	CLAIREVILLE		500	Yes
ESSA	CLAIREVILLE		500	Yes
ESSEX			115	Yes
ESSA	ORANGEVILLE		230	Yes
ESSEX			115	Yes
ESSA	ORANGEVILLE		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
MERIVALE	HINCHEY		115	No
FREEMONT	CEDAR		115	No
FREEMONT	CEDAR		115	No
FORT FRANCES			115	No
CALSTOCK SS	KAPUSKASING	SPRUCEFALLS	115	Yes
FORT FRANCES	MACKENZIE		230	Yes
FORT FRANCES			115	No
FORT FRANCES	MN - INTERNATIONAL F		115	Yes
HEARN	ESPLANADE	JOHN	115	No
HEARN	LEASIDE		115	Yes
HEARN	PORTLANDS		115	Yes
HEARN	PORTLANDS		115	Yes
HEARN	PORTLANDS		115	Yes
HEARN	LEASIDE		115	Yes
HARMON	PINARD		230	Yes
HINCHINBROOK	BELLEVILLE		230	Yes
HOLDEN	MARTINDALE		230	Yes
HAVELOCK	CHERRYWOOD NORTH		230	Yes
HOLDEN	MARTINDALE		230	Yes
HAVELOCK	CHERRYWOOD NORTH		230	Yes
HINCHINBROOK	HAVELOCK		230	Yes
HURONTARIO			230	No
HEARN	JOHN	MANBY WEST	115	No
CALSTOCK DS JCT	CALSTOCK DS		115	No
HURONTARIO			230	No
HAMILTON BEACH	DOFASCO		230	Yes
HAMILTON BEACH	DOFASCO		230	Yes
HEARN	LEASIDE		115	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
HOLDEN	PQ - RAPIDE DES ISLE		115	No
HAMILTON BEACH	KENILWORTH		115	No
HAMILTON BEACH	KENILWORTH		115	No
HEARN	LEASIDE	CECIL	115	No
HUNTA	TIMMINS		115	Yes
HEARN	LEASIDE		115	Yes
HUNTA	TIMMINS		115	Yes
HEARN	LEASIDE	CECIL	115	No
PQ - MASSON	HAWTHORNE		115	No
HEARN	ESPLANADE	JOHN	115	No
HUNTA	KAPUSKASING		115	Yes
HAMILTON BEACH			115	No
HAMILTON BEACH			115	No
KEITH	BRIGHTON BEACH		115	Yes
KEITH	BRIGHTON BEACH CGS		230	Yes
KEITH	WEST WINDSOR		115	Yes
KEITH	ESSEX		115	Yes
KEITH	ESSEX		115	Yes
KEITH	MI - WATERMAN		230	Yes
MANBY EAST	WILTSHIRE		115	No
KARN	WOODSTOCK		115	No
MANBY EAST	WILTSHIRE		115	No
MANBY WEST	JOHN		115	No
MANBY WEST	JOHN		115	No
KENILWORTH	GAGE		115	No
MANBY EAST	WILTSHIRE		115	No
KIRKLAND LAKE			115	Yes
MANBY WEST	COOKSVILLE		230	Yes
KENORA	MB - WHITESHELL		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
KENORA	MB - WHITESHELL		230	Yes
MANBY EAST	COOKSVILLE		230	Yes
KENORA	DRYDEN		230	Yes
KENORA	FORT FRANCES		230	Yes
KENILWORTH	GAGE		115	No
ABKENORA	RABBIT LAKE		115	No
KENT	LAUZON		115	No
SMOKY FALLS			115	No
KAPUSKASING	SPRUCE FALLS		230	Yes
RABBIT LAKE	DRYDEN		115	Yes
MANBY EAST	WILTSHIRE		115	No
KIRKLAND LAKE			115	No
SANDUSK SS	MIDDLEPORT		230	Yes
RABBIT LAKE	WHITEDOG		115	Yes
RABBIT LAKE	WHITEDOG		115	Yes
RABBIT LAKE	FORT FRANCES		115	Yes
MANBY WEST	JOHN		115	No
KINGSVILLE	LAUZON		115	No
KARN	WOODSTOCK		115	No
KENORA	RABBIT LAKE		115	Yes
LEASIDE	CECIL		115	No
LEASIDE	WILTSHIRE		115	No
LEASIDE	WILTSHIRE		115	No
LEASIDE	WILTSHIRE		115	No
LEASIDE	DUPLEX		115	No
ST LAWRENCE	MERIVALE	BROCKVILLE	115	Yes
CRYSTALFALLS	MARTINDALE		115	Yes
LITTLE LONG	PINARD		230	Yes
ST LAWRENCE	HINCHINBROOK		230	Yes
ST LAWRENCE	HINCHINBROOK		230	Yes
LITTLE LONG	KAPUSKASING		230	Yes
ST LAWRENCE	HINCHINBROOK		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
LAMBTON	SCOTT		230	Yes
ST LAWRENCE	HAWTHORNE		230	Yes
LAMBTON	LONGWOOD		230	Yes
LAMBTON	NOVA SS		230	Yes
LAMBTON	LONGWOOD		230	Yes
LAMBTON	NOVA SS		230	Yes
LAMBTON	CHATHAM		230	Yes
LAMBTON	CHATHAM		230	Yes
ST LAWRENCE	MERIVALE		115	Yes
LEASIDE	GLENGROVE		115	No
ST LAWRENCE	NY FDR-MOSES		230	Yes
ST LAWRENCE	NY FDR-MOSES		230	Yes
LAMBTON	GREENFIELD		230	Yes
LAMBTON	GREENFIELD		230	Yes
LAKEHEAD	PORT ARTHUR		115	Yes
LEASIDE	CHARLES		115	No
LAMBTON	MI - ST CLAIR		345	Yes
LAKEHEAD	PORT ARTHUR		115	Yes
LAMBTON	MI - ST CLAIR		230	Yes
ST LAWRENCE			115	No
LEASIDE	DUPLEX		115	No
CRYSTAL FALLS	HOLDEN		115	Yes
ST MARY	SEAFORTH		115	No
LEASIDE	CECIL		115	No
MERIVALE	RUSSELL		115	No
MOOSE LAKE	STURGEON FALLS		115	No
MIDDLEPORT	DETWEILER		230	Yes
MIDDLEPORT	DETWEILER		230	Yes
MARATHON	LAKEHEAD		230	Yes
MARATHON	LAKEHEAD		230	Yes
MIDDLEPORT	BURLINGTON		230	Yes
MIDDLEPORT	BURLINGTON		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
ALMONTE TS	CHERRYWOOD TS		230	Yes
ALMONTE TS	MERIVALE TS		230	Yes
MOOSE LAKE	DRYDEN		115	Yes
MARATHON	WHITE RIVER		115	No
MERIVALE	HAWTHORNE		230	Yes
MERIVALE	HAWTHORNE		230	Yes
MIDDLEPORT	BUCHANAN		230	Yes
MERIVALE	SOUTH MARCH		230	Yes
MIDDLEPORT	BUCHANAN		230	Yes
MIDDLEPORT	BUCHANAN		230	Yes
HAMILTON BEACH	MIDDLEPORT		230	Yes
MANITOU FALLS	EAR FALLS		115	Yes
MOOSONEE SS	KASHECHEWAN		115	No
MERIVALE	LISGAR		115	No
MILTON	CLAIREVILLE		500	Yes
MILTON	CLAIREVILLE		500	Yes
MILTON	TRAFALGAR		500	Yes
MILTON	TRAFALGAR		500	Yes
MILTON	MIDDLEPORT		500	Yes
MERIVALE	LISGAR		115	No
MINDEN	ESSA		230	Yes
MINDEN	ESSA		230	Yes
MINDEN	BROWN HILL		230	Yes
MINDEN	BROWN HILL		230	Yes
MOOSONEE SS	KASHECHEWAN		115	No
SCOTT	SUNOCO		115	No
NANTICOKE	SANDUSK SS		230	Yes
NANTICOKE	JARVIS		230	Yes
SCOTT	BUCHANAN		230	Yes
NANTICOKE	JARVIS		230	Yes
SCOTT	BUCHANAN		230	Yes
SUMMERHAVEN SS	Nanticoke TS		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
SCOTT	SUNOCO		115	No
NANTICOKE	MIDDLEPORT		500	Yes
NANTICOKE	MIDDLEPORT		500	Yes
NANTICOKE	LONGWOOD		500	Yes
SCOTT	KENT		115	No
NANTICOKE	MIDDLEPORT		230	Yes
SCOTT	ST ANDREW		115	No
NANTICOKE	MIDDLEPORT		230	Yes
SCOTT	TA SARNIA		230	Yes
SCOTT	ST ANDREW		115	No
SCOTT	TA SARNIA		230	Yes
MACKENZIE	ATIKOKAN		230	Yes
PORCUPINE	TIMMINS		115	Yes
DOBBIN	CHERRYWOOD NORTH		230	Yes
PORCUPINE	TIMMINS		115	Yes
PORT ARTHUR	PROVINCIAL PAPERS		115	No
PORT ARTHUR	THUNDRBAY PAC		115	No
MISSISSAGI	THIRDLINE		230	Yes
PARKWAY	RICHVIEW		230	Yes
RICHVIEW	PARKWAY		230	Yes
MISSISSAGI	WAWA		230	Yes
MISSISSAGI	WAWA		230	Yes
PICKERING B	CHERRYWOOD NORTH		230	Yes
PICKERING B	CHERRYWOOD NORTH		230	Yes
PICKERING B	CHERRYWOOD SOUTH		230	Yes
PICKERING B	CHERRYWOOD SOUTH		230	Yes
PQ - PAUGAN	CHATS FALLS		230	Yes
PORT ARTHUR	BIRCH		115	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
DOBBIN	SIDNEY		115	No
PARKWAY			230	Yes
PARKWAY			230	Yes
DOBBIN	SIDNEY		115	No
PORCUPINE	HANMER		500	Yes
PORT ARTHUR			115	Yes
PICKERING A	CHERRYWOOD NORTH		230	Yes
PORT ARTHUR	BIRCH		115	Yes
PICKERING A	CHERRYWOOD SOUTH		230	Yes
PORCUPINE	KIDDCREEK		115	No
PICKERING A	CHERRYWOOD NORTH		230	Yes
PORCUPINE	ANSONVILLE		230	Yes
PICKERING A	CHERRYWOOD SOUTH		230	Yes
BECK 2	NY NIAGARA		230	Yes
BECK 2	NY NIAGARA		230	Yes
BECK 2	NY NIAGARA		230	Yes
BECK 2	NY NIAGARA		345	Yes
BECK 2	NY NIAGARA		345	Yes
THOROLD GS			230	Yes
BECK 1	GLENDALE		115	No
BECK 1	GLENDALE		115	No
BECK 1			115	No
BECK 2	BECK 2 PGS		230	Yes
BECK 2	BECK 2 PGS		230	Yes
BECK 2	BURLINGTON	MIDDLEPORT	230	Yes
BECK 2	HAMILTON BEACH	MIDDLEPORT	230	Yes
BECK 2	BURLINGTON	MIDDLEPORT	230	Yes
BECK 2	MIDDLEPORT		230	Yes
BECK 2	ALLANBURG		230	Yes

Witness: Mike Penstone

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
BECK 2	HAMILTON BEACH	MIDDLEPORT	230	Yes
BECK 1			115	No
BECK1	ALLANBURG	HAMILTON BEACH	115	Yes
BECK 2	MIDDLEPORT		230	Yes
BECK 2	MIDDLEPORT		230	Yes
CATARAQUI	FRONTENAC		115	No
BECK 1	Murray		115	Yes
CATARAQUI			115	No
THUNDERBAY	BIRCH		115	No
PQ - QUYON	CHATS FALLS		230	No
BECK 1	MURRAY		115	Yes
THUNDER BAY	BIRCH		115	No
BECK 1			115	No
BECK 1			115	No
CATARAQUI	SIDNEY		115	No
THUNDER BAY	BIRCH		115	No
THUNDER BAY	BIRCH		115	Yes
RICHVIEW	MANBY EAST		230	Yes
RICHVIEW	TRAFALGAR		230	Yes
RICHVIEW	MANBY WEST		230	Yes
RICHVIEW	TRAFALGAR		230	Yes
RICHVIEW	TRAFALGAR	HURONTARIO	230	Yes
RICHVIEW	MANBY EAST		230	Yes
PINE PORTAGE	LAKEHEAD	BIRCH	115	Yes
OTTER RAPIDS	PINARD		230	Yes
RICHVIEW	HURONTARIO	TRAFALGAR	230	Yes
RICHVIEW	COOKSVLE		230	Yes
RICHVIEW	MANBY WEST		230	Yes
PINE PORTAGE	LAKEHEAD	BIRCH	115	Yes
PINE PORTAGE	ALEXANDER SS		115	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
SILVER FALLS	SILVER FALLS JCT		115	Yes
OWEN SOUND	HANOVER		115	No
BATTERSEA	FRONTENAC		115	No
MARTINDALE			115	No
MARTINDALE	INCO		230	Yes
MARTINDALE	ALGOMA		230	Yes
SAUNDERS	ST LAWRENCE		230	Yes
SAUNDERS	ST LAWRENCE		230	Yes
MARTINDALE	ALGOMA		115	No
STRATHROY	SCOTT		115	No
OWEN SOUND	STAYNER		115	No
ORANGEVILLE	SHANNON CSS		230	Yes
SAUNDERS	ST LAWRENCE		230	Yes
SAUNDERS	ST LAWRENCE		230	Yes
SUMMERHAVEN SS	MIDDLEPORT	SUMMERHAVEN SS	230	Yes
SPRUCE FALLS	SMOKY FALLS		115	No
CHATHAM	SPENCE		230	Yes
SPRUCE FALLS	SMOKY FALLS		115	No
MARTINDALE			115	No
MARTINDALE			115	No
SOUTH MARCH SS	MERIVALE		115	Yes
RABBIT LAKE	SEVEN SISTERS		115	No
ST THOMAS	TILLSONBURG		115	No
ALGOMA			115	Yes
TERRACE BAY	MARATHON		115	Yes
WELLS	MISSISSAGI		230	Yes
WELLS	MISSISSAGI		230	Yes
TIMMINS	Wawaitin		27.6	No
TRAFALGAR	BURLINGTON		230	Yes
TRAFALGAR	BURLINGTON		230	Yes
TRAFALGAR	BURLINGTON		230	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
TRAFALGAR	BURLINGTON		230	Yes
TIMMINS			115	No
OTTERRAPID SS	MOOSONEE SS		115	No
OTTERRAPID SS	MOOSONEE SS		115	No
KENT			115	No
MERIVALE	HINCHEY		115	No
CLAIREVILLE	HURONTARIO		230	Yes
SCOTT	NOVA SS		230	Yes
CLAIREVILLE	HURONTARIO		230	Yes
CLAIREVILLE			230	Yes
SCOTT	NOVA SS		230	Yes
CLAIREVILLE			230	Yes
CLAIREVILLE	MIDDLEPORT		500	Yes
CLAIREVILLE	PARKWAY		230	Yes
CLAIREVILLE	RICHVIEW		230	Yes
CLAIREVILLE	RICHVIEW		230	Yes
CLAIREVILLE	RICHVIEW		230	Yes
CLAIREVILLE	PARKWAY		230	Yes
CLAIREVILLE	RICHVIEW		230	Yes
CLAIREVLE	RICHVIEW		230	Yes
CLAIREVLE	RICHVIEW		230	Yes
BUCHANAN			115	No
WHITEDOG FALLS			115	No
WAWA	MARATHON		230	Yes
WAWA	MARATHON		230	Yes
WAWA	MACKAY TS		230	Yes
WAWA	CHAPLEAU		115	No
BUCHANAN	STRATHROY		115	No
BUCHANAN			230	Yes
BUCHANAN			230	Yes
STEWARTVILLE	BARRETT CHUTE		115	Yes
WHITEDOG	CARIBOU FALLS		115	Yes
BUCHANAN	ST THOMAS		115	No

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
BUCHANAN	LONGWOOD		230	Yes
BUCHANAN	LONGWOOD		230	Yes
BUCHANAN	LONGWOOD	CHATHAM	230	Yes
BUCHANAN	LONGWOOD	Spence SS	230	Yes
BUCHANAN	ST THOMAS		115	No
BUCHANAN	NELSON		115	No
STEWARTVILLE	CHATS FALLS	SOUTH MARCH SS	115	Yes
BUCHANAN	NELSON	HIGHBURY	115	No
BUCHANAN			115	No
WIDDIFIELD	DYMOND		230	Yes
BUCHANAN	TILLSONBURG		115	Yes
BUCHANAN	HIGHBURY		115	No
LYONS JCT	AYLMER		115	No
PORT BURWELL	TILLSONBURG		115	No
BUCHANAN	LAFARGE		115	No
LENNOX	HINCHINBROOK		230	Yes
CHENAUX	DOBBIN		230	Yes
LENNOX			230	No
LENNOX			230	No
HANMER	INCO		230	Yes
HANMER	MARTINDALE		230	Yes
HANMER	MARTINDALE		230	Yes
HANMER	ALGOMA		230	Yes
LENNOX	HINCHINBROOK		230	Yes
CHENAUX	PQ - BRYSON		115	No
LENNOX	HINCHINBROOK		230	Yes
LENNOX	HINCHINBROOK		230	Yes
HANMER	ESSA		500	Yes
HANMER	ESSA		500	Yes
LENNOX	DARLINGTON		500	Yes
LENNOX	DARLINGTON		500	Yes
LENNOX	HAWTHORNE		500	Yes

Bus1	Bus2 (if applicable)	Bus3 (if applicable)	kV	BES (NERC)
LENNOX	HAWTHORNE		500	Yes
LENNOX	DARLINGTON		500	Yes
LENNOX	DARLINGTON		500	Yes
CHENAUX			115	No
MISSISSAGI	HANMER		230	Yes
LAUZON	ESSEX		115	Yes
LAUZON	ESSEX		115	Yes

TRANSMISSION SYSTEM MAPS

Northern Ontario System

Southern Ontario System

TRANSMISSION BUSINESS PERFORMANCE

1. INTRODUCTION

This exhibit focuses on the historical performance of Hydro One's transmission business in three areas of the business objectives; safety, customer satisfaction and reliability. Trending and external benchmarking help identify areas that Hydro One should focus on to improve the performance of the transmission business. In an effort to promote continuous improvement across the Company, Hydro One has developed a proposed transmission scorecard as well as line of business metrics and key performance indicators to help the Company manage, monitor and evaluate its transmission business performance (Exhibit B2, Tab 1, Schedule 1).

2. PERFORMANCE MEASUREMENT PROCESS

The assessment of a utility's performance can be made using comparisons to other utilities or through a comparison of its own year-over-year performance trends. This exhibit includes both of these comparisons and Hydro One understands that analysis of this nature is a priority of the Board and the stakeholder community. For example, in the area of customer satisfaction, Hydro One has presented its year-over-year trended performance as a comparison to other utilities is not available. On the other hand, comparisons to others in the areas of safety and reliability focus on the established Canadian Electricity Association (CEA) composite performance indicator, which is the aggregate performance of CEA participating transmission utilities from across Canada, some of which are government-owned.

Benchmarking results, particularly for reliability performance, need to be considered in the context of:

- measurement definition;
- data collection processes, which impact the consistency and accuracy of the reported measures; and
- variations such as climate, operating environment and system infrastructure amongst transmission companies that can influence the results.

A way to reduce the effect of these factors is to observe year-over-year performance using consistent and precise measurement definitions. Although individual transmitters may have a slightly different approach when measuring their own transmission system performance, the Canadian Electricity Association (CEA) has had success in creating reliability performance definitions with sufficient precision and consistency over the years to permit some degree of multi-jurisdictional transmission system performance comparisons. The comparisons are useful to provide insights and identify potential opportunities for business improvement.

3. SAFETY PERFORMANCE

Health and safety is of paramount importance in the operation of Hydro One's business. The company has targeted and continues to maintain top quartile performance in these key areas and to achieve the world class rate of less than one incident in 200,000 hours. Hydro One continues to develop, implement and maintain progressive programs and initiatives relating to health and safety. Hydro One is committed to achieving and maintaining an injury-free workplace and maintaining public safety, with a concentrated focus on the elimination of serious injuries or "near-misses" which have the potential to cause serious injuries. The company has also developed and is continuing to develop a number of programs and initiatives for accident prevention and to minimize the risk of injury to the public through contact with energized equipment associated with Hydro One facilities and operations. Policies are in place for both employee health and safety and public safety.

Since the Hydro One safety program encompasses the entire company, safety performance is tracked on a company-wide basis and performance measurement results are not divided between the transmission and distribution businesses. The results presented in this evidence are for all of Hydro One.

3.1 Safety Initiatives

3.1.1 Journey to Zero Initiative

Hydro One has continued with its Journey to Zero safety initiative that was started in 2010. Journey to Zero is Hydro One's primary Health and Safety continuous improvement process. It is based on the goals, beliefs and commitment made in the Health and Safety Policy. This initiative compares Hydro One's approach to health and safety management with world class companies to identify where gaps might exist. Opportunities for improvement were prioritized and implementation continued during 2015, including a focus on the following areas:

- Journey to Zero initiatives including:
    - a safety culture assessment by DuPont Sustainable Solutions Safety Resources, with a survey, site assessment, leadership interviews and focus groups;
    - reducing electrical contacts;
    - identifying and preventing Musculoskeletal Disorders (MSDs); and
    - Reducing slips and trips;
- Workplace Safety Observations;

- Mental Health Strategy implementation; and
- The Five Safety Basics (Identify, Eliminate, Control, Protect, Minimize).

The Journey to Zero program focuses on achieving world class performance in this metric by 2019. World class performance is considered to be an injury/work-related illness rate of less than one per 200,000 hours worked on an annual basis. The metric measures the number of injuries that require treatment by a medical practitioner that are beyond first aid.

3.1.2 Health Safety and Environment Management System (HSEMS)

Hydro One implements its Corporate Health and Safety Policy, Environment Policy and Public Safety Policy through the Health Safety and Environment Management System (HSEMS). The HSEMS has been registered to the OHSAS 18001 standard since 2013. Maintenance of this registration requires annual external system audits which Hydro One has successfully passed since Hydro One’s registration in 2013. Effective risk and hazard identification, assessment and management are key elements to successful performance improvement and are documented in the HSEMS. Objectives, targets, accountabilities and work programs specific to each line of business are created as part of the HSEMS Operational Plan to address these risks and hazards. The progress to achieving the stated objectives is reported on a quarterly basis. These activities all contribute to Hydro One’s Journey to Zero objective of achieving world class safety performance by 2019.

During 2015, several initiatives were implemented as part of Hydro One’s HSEMS Operational Plan. These initiatives address Musculoskeletal Disorders (MSDs) and slip and trip injuries, as work continues to achieve the goal of zero injuries. Through a continuing review of incidents, the company will identify the causal factors of work-related illnesses or injuries and implement preventative measures and training where possible.

3.2 Internal Trending of Safety Performance

3.2.1 Internal Trending

Improvement in recordable injury performance can be seen in the ten-year trend set out in Figure 1. Figure 1 illustrates that the initiatives implemented through the Health Safety and Environment Management System (HSEMS) and Journey to Zero programs have helped drive a more safety conscious culture within Hydro One.

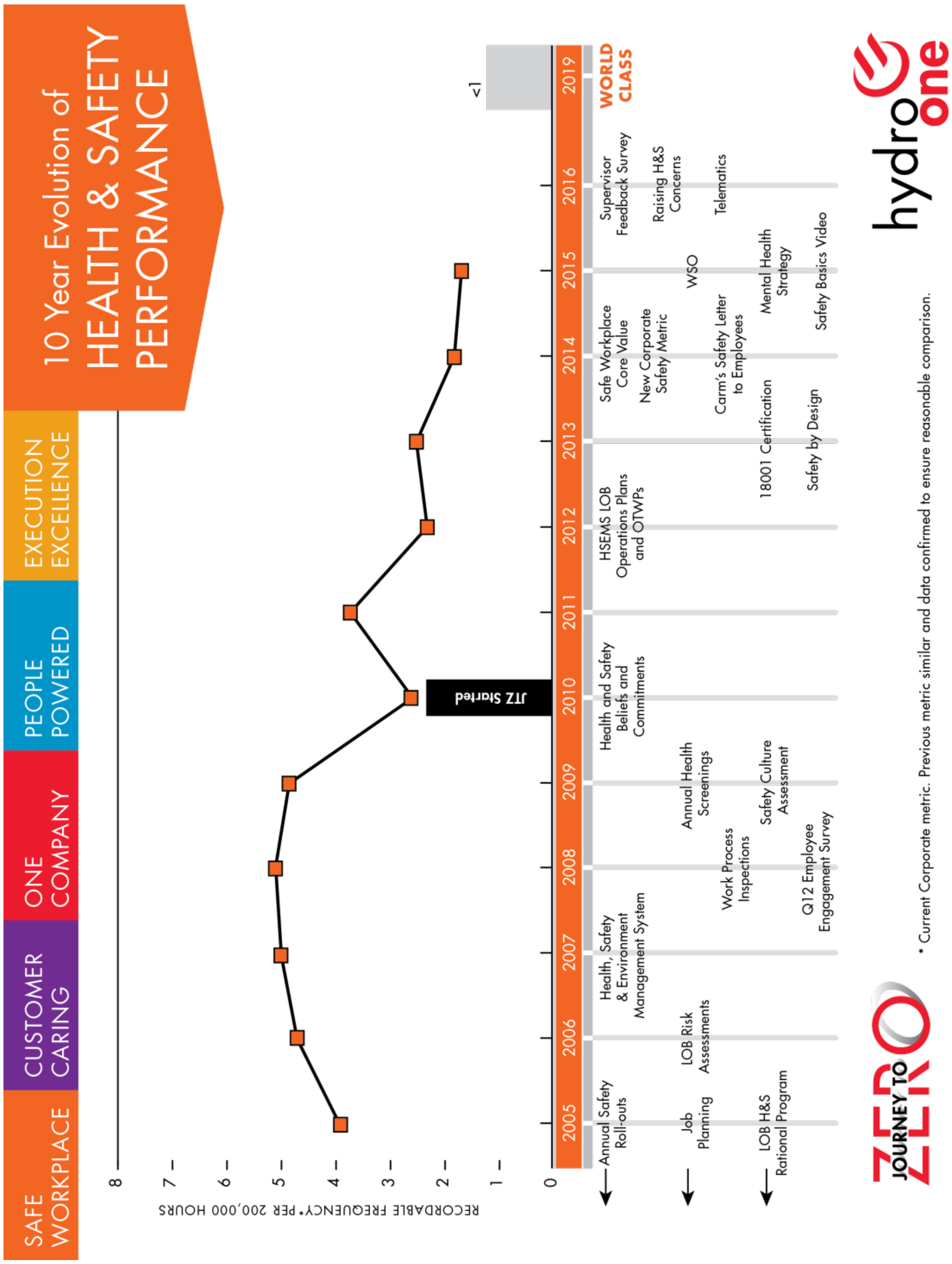

Figure 1: Ten Year Safety Performance Trend

Legend: LOB = Line of Business; H&S = health and safety; Q12 = Gallup Engagement Process; OTWP = Objectives, Targets & Work Programs; JTZ = Journey to Zero; WSO = Workplace Safety Observation

3.2.2 External Comparisons of Safety Performance

3.2.2.1 The Recordable Injury/Illness Frequency Rate

Hydro One's safety performance is measured by the Recordable Injury/Illness (work-related illness) Frequency Rate, an industry-recognized metric. The metric measures the number of injuries that require treatment by a medical practitioner that are beyond first aid. The Recordable Injury/Illness metric measures the success of planned improvement initiatives in the prevention of injuries and is aligned with the Canadian Electricity Association (CEA) Recordable Rate metric and the US Occupational Safety and Health Administration metric. Hydro One's safety performance compared to other Canadian utilities using the recordable rate metric is shown in Figure 2 (note: 2015 CEA data not released).

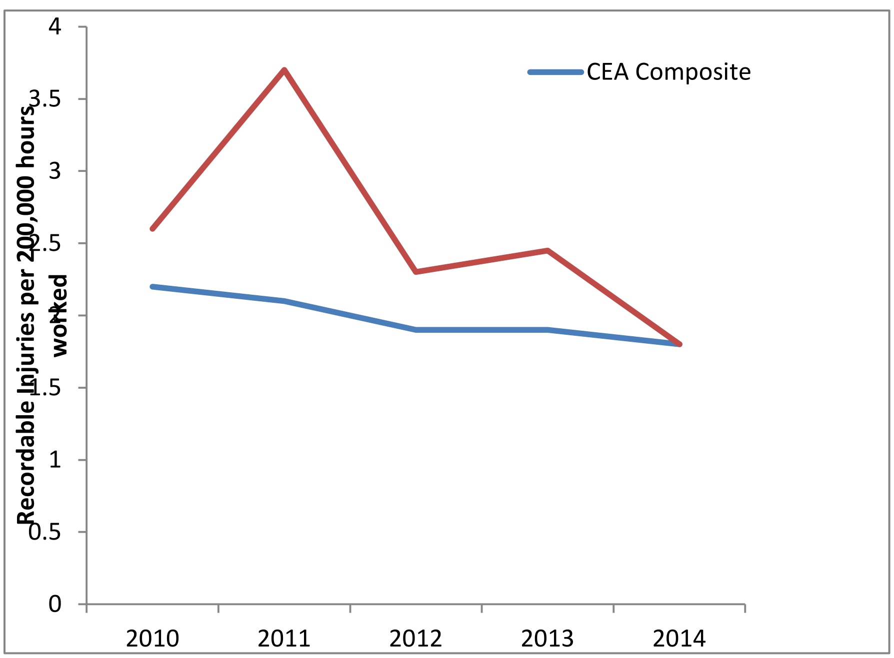

Figure 2: Hydro One Recordable Rate Comparison to CEA Average

3.2.2.2 Motor Vehicle Accident Rate

Another metric used by the CEA is recordable licenced fleet motor vehicle incident rate for on-road vehicles only, where the collision results in over $5,000 damage or a recordable injury. Hydro One's performance compared to other Canadian utilities for this metric is illustrated in Figure 3 (note: 2015 CEA data not released).

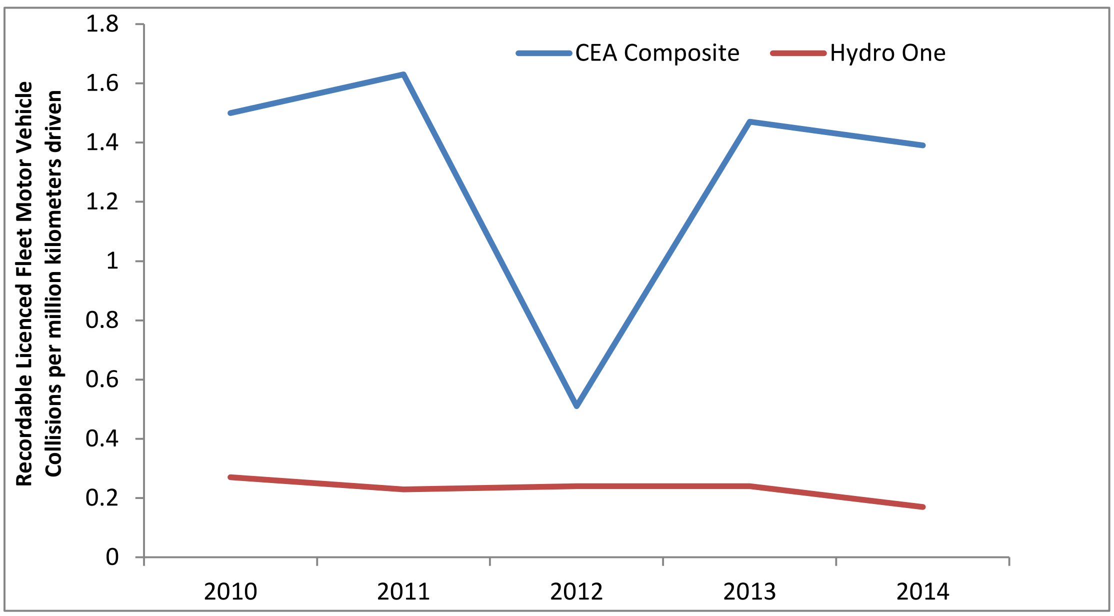

Figure 3: Hydro One Recordable Licenced Fleet Motor Vehicle Rate Comparison to CEA Average

In 2015, Hydro One's Driver Safety Program was updated to include new requirements for the mandatory installation of winter tires, investigation of driving violations and collisions, improved clarity on performance of inspections and associated paperwork, and clarification on commercial vehicle operation registry (CVOR) monitoring. The new program incorporates training on the driver safety program, defensive driving, CVOR legislation, hands-on motor vehicle operation, and classified licences. Mandatory information packages to be delivered at safety meetings have been introduced to review distracted driving, pedestrian crossings, winter driving, traffic control, log books and circle checks to inspect the condition of the vehicle prior to use on a daily basis with all Hydro One staff. Telematics training has also been introduced. See Exhibit C1, Tab 5, Schedule 1 for further details on telematics. Defensive driving and driver safety program training programs are being revised in 2016 and delivered to staff. These awareness programs are expected to result in an overall reduction of preventable motor vehicle accidents by 10% by year end 2017.

Metrics for injuries, illnesses and motor vehicle collision rates are monitored by Hydro One Management and by the Health, Safety, Environment and First Nations & Metis Relations Committee of the Board of Directors.

When an injury or illness does occur, Hydro One has implemented an effective early and safe return to work program to assist employees in their medical treatment.

4. CUSTOMER SATISFACTION

Customer Satisfaction is a key component of Hydro One's corporate strategy. Improving customer satisfaction levels is one of Hydro One's business objectives. The company listens to its customers, analyzes their needs and modifies the work planning and activities to address those needs. For further discussion on Hydro One's customer engagement activities that are used to inform the investment plan, refer to Exhibit B1, Tab 2, Schedule 2. This Exhibit focuses on customer satisfaction surveys that are conducted to gain an understanding of the key drivers impacting transmission customer satisfaction.

All research is conducted by independent, third parties with customer engagement expertise to ensure that survey results are unbiased. Northstar Fearless Intellect

("Northstar") conducts the Transmission Customer surveys. Northstar ensures that the sample size and methodology are appropriate so that findings are representative. The trending of results identifies opportunities to improve transmission customer satisfaction.

4.1 Customer Surveys

4.1.1 Large Transmission Customer Survey

This survey is performed annually. The objectives of the Large Transmission Customer survey are to measure the level of customer satisfaction, and to monitor Hydro One's performance in four key areas: Price, Customer Service, Product Quality / Reliability and Relationship. The surveys measure customers' perception of the company (whether they have interacted with Hydro One recently or not), with a specific focus on how well the company meets their expectations and delivers on critical success factors.

All interviews were conducted either online or by computer-assisted telephone interviewing, depending on the customers' preferred method of communication. In 2015, the survey had a response rate of 64%. Table 1 outlines the surveyed customer segments and survey sample size.

Table 1: Surveyed Customer Segments

Year	End Users	LDCs	Generators
2015	34	50	32

*Note: All LDCs were included in the study

4.1.2 Overall Satisfaction

The survey is administered to transmission-connected Generators, End Users and Local Distribution Companies (LDCs). The customer survey research is used to evaluate the overall satisfaction levels of these customers, and to better understand their perception of Hydro One. The data is also used to identify customer issues. Figure 4 illustrates the trending of the overall satisfaction results. Figure 5 shows the overall satisfaction level for each of the three customer segments.

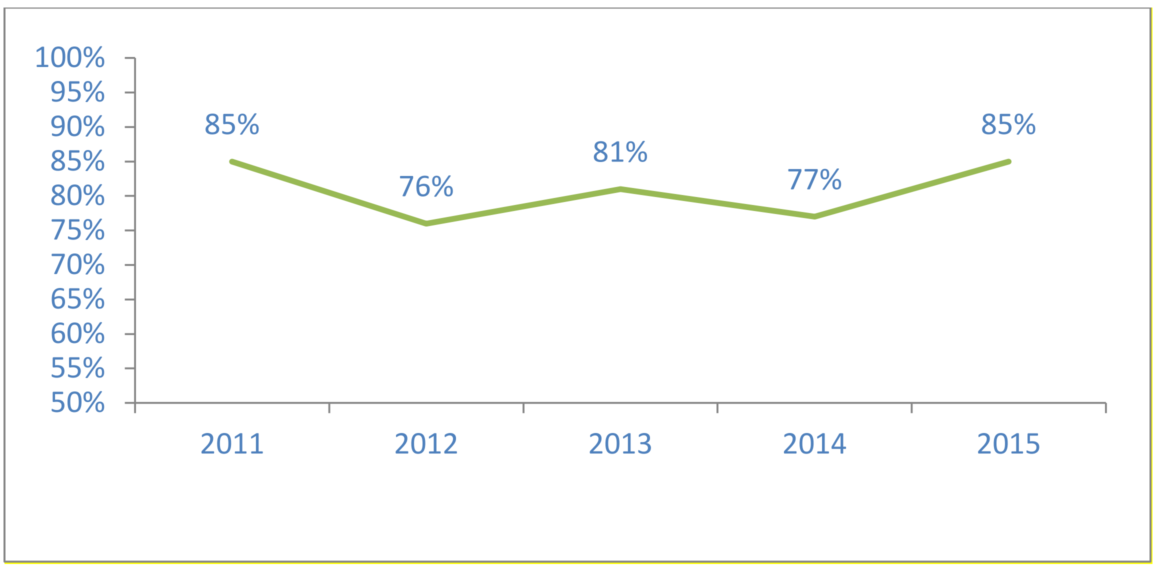

Figure 4: Overall Satisfaction

The overall satisfaction (combined results) improved by 8% from 77% in 2014 to 85% in 2015. Overall satisfaction is currently at its highest point since 2011.

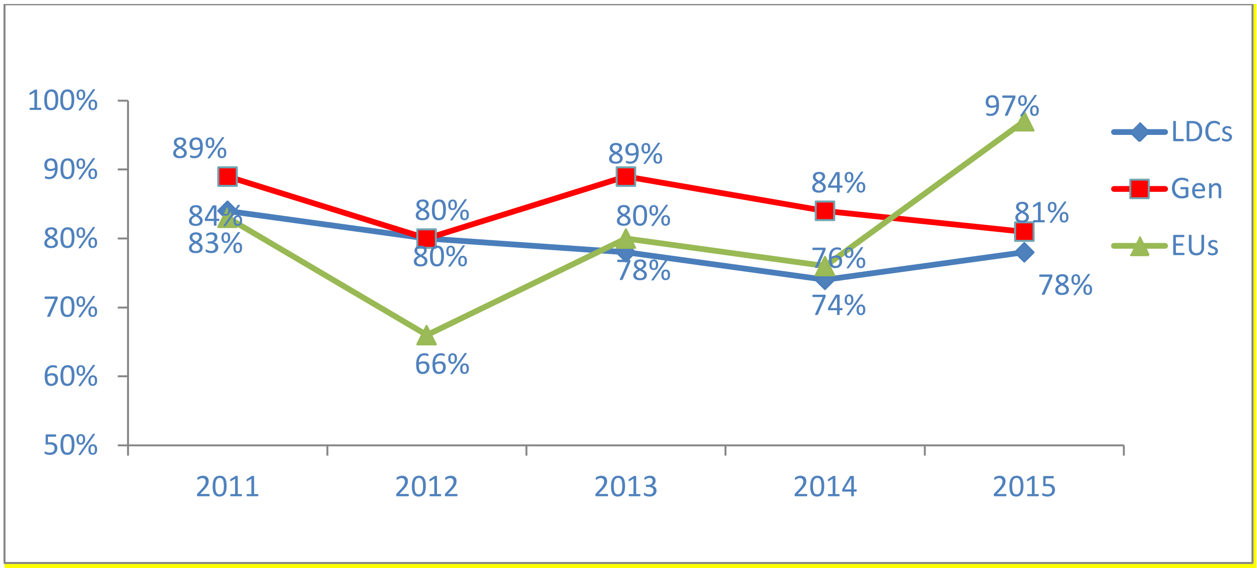

Figure 5: Overall Satisfaction by Customer Segment

4.1.3 Customer Segment Satisfaction Ratings

<u>End Users</u>

The increase in the combined overall satisfaction result shown in Figure 4 is largely attributed to increases in End User satisfaction levels. End Users scores indicate that they experienced improvements with their Account Executive having the authority to make decisions. By contrast, product issues such as Reliability & Power Quality continue to be the areas of concern for customers, with nearly one third (32%) of respondents citing this as the "main need to address".

Local Distribution Companies (LDCs)

LDCs have reversed a five year downward trend, with satisfaction results returning to 2013 levels as illustrated in Figure 5. The main area where improvements were observed concerned Hydro One's ability to keep commitments (a 14% percentage point increase). The main challenges noted by LDC customers were issues with customer relations, most notably communication and responsiveness.

Generators

Historically, Generator customers have been the most satisfied with Hydro One as shown in Figure 5, but 2015 results indicated a reduction in satisfaction among this customer group. Generator customers' satisfaction regarding the duration of unplanned outages has decreased significantly. This customer segment group indicates that planning issues (outage planning, infrastructure upgrades) are key areas to be addressed.

4.1.4 Key Satisfaction Drivers

Northstar analyzed the data and grouped it into the four key areas mentioned in Section 4.1.1. Figure 6 is a graphical representation of how Hydro One's performance has been trending in these key areas. In three of the key areas, Hydro One has shown improvement since 2012.

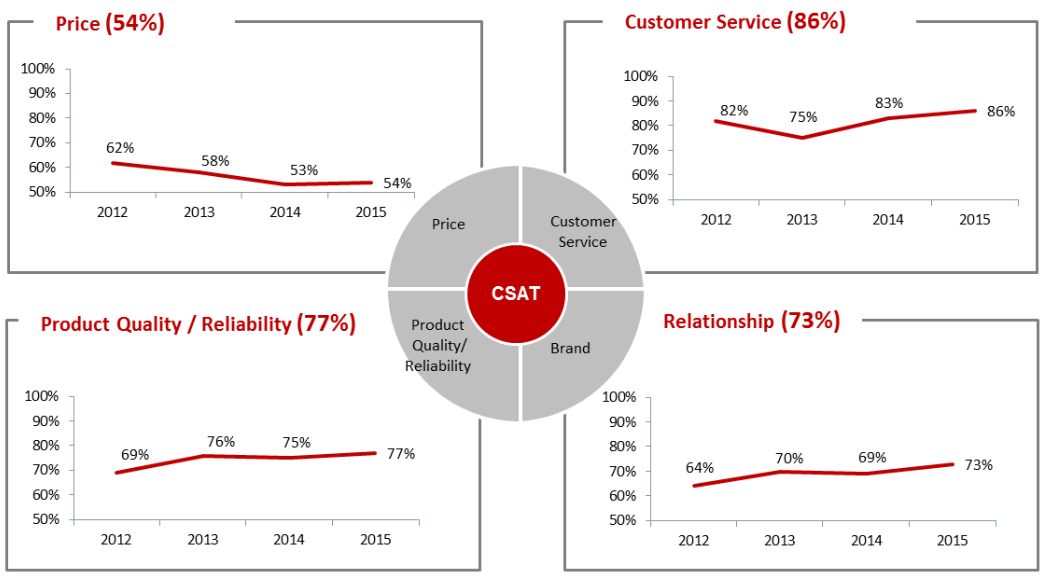

Figure 6: Trending for Key Satisfaction Drivers

The changes noted in Figure 6 are explained below:

- The slight improvement in satisfaction with price may be attributed to customized conservation advice received on a per customer basis.
- Customers' scores indicated an increased level of satisfaction with product quality / reliability due to the feeling that they had a partnership in electricity delivery. However they were dissatisfied with their level of reliable delivery of electricity.
- Customer Service saw its greatest improvement related to the Account Executive. They appreciate that the Account Executive has the authority to make decisions and were satisfied with most recent contact with their Hydro One Account Executive.
- With respect to relationship, customers appreciate that Hydro One respects the needs of their business.

4.2 Ontario Grid Control Centre Transmission Customer Surveys

Since 2003, Ontario Grid Control Centre's (OGCC) medium and large business customer satisfaction has been surveyed. Originally, focus groups were conducted to help develop the survey questions and key areas of attention. A full survey is administered on a bi-annual basis (even-numbered years) that includes a comprehensive analysis of the responses to identify any trends and possible areas for improvement. Beginning in 2015, a smaller, mini-survey was introduced to be administered in odd-numbered years. The key objectives of these surveys are to determine key drivers of satisfaction, strengths and weaknesses and provide recommendations for continuous improvement to customer service policy, programs, service delivery processes and communications related to the areas of accountability of the OGCC.

Customer feedback is important to Hydro One as it identifies areas for Hydro One to focus on to improve the customer experience. Customers are invited to participate in the OGCC customer survey by email. The primary email invitation includes information on how to complete the survey on line and is then followed by two reminder e-mails to non-respondents. After that if the customer has not completed the survey, NorthStar will phone and discuss arrangements to make it more convenient for the customer to respond to the survey (e.g. extend the time to respond on line, complete the survey on the phone, schedule a time to respond by phone).

Table 2: Surveyed Customer Segments

Segment Size	End Users	Generators	LDCs	Total Responses	Response Rate
2014	91*	52	N/A*	143	63%
2015	52	43	45	140	63%

*Prior to 2015 End Users included LDC respondents

Customers generally report a high level of overall satisfaction with the OGCC. Consistent with the results in 2014, nine in ten customers remain satisfied with the OGCC's ability to understand their needs. However, 2015 saw a notable decline in overall satisfaction with the OGCC, largely attributable to a small number of respondents (ten) that were dissatisfied and indicated issues with planning and stated that requested outages were overlooked, ignored or delayed. The OGCC is working on improving communication on the processes, reports and meetings offered to the customer to improve satisfaction with the OGCC. At subsequent customer meetings there have been follow up discussions to understand what the customer is specifically looking for and if these tools and programs are sufficient.

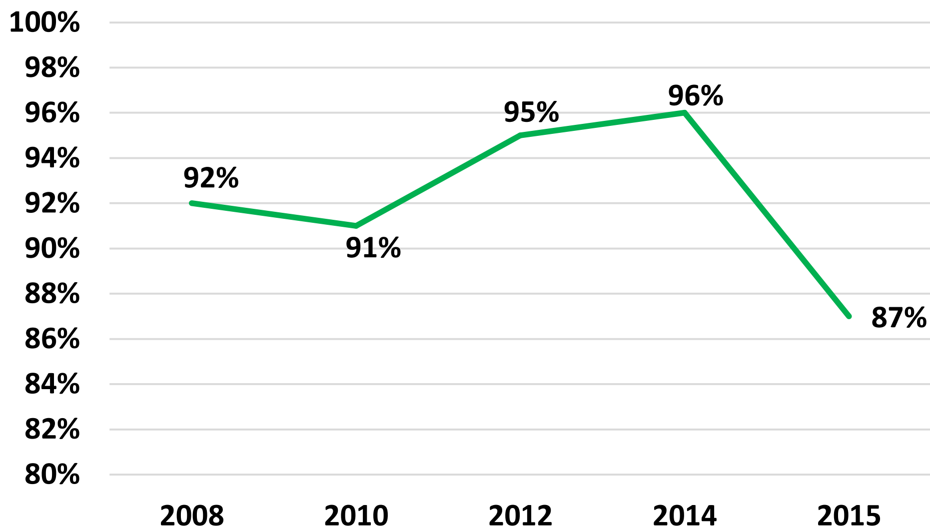

Figure 7: Overall Satisfaction with the OGCC

One of the OGCC's strengths is its Control Room services. The Control Room deals with the real time operation of the transmission system and provides customers with update information regarding any impact the transmission system may have on their business. Customers believe that this department provided the right information (95%) and timely information (95%). Of note, complete, timely communication has improved, along with the incidence of, and satisfaction with, scheduled meetings. Improvement of OGCC Staff knowledge of the customers' business and needs has been noted by customers. Efforts continue to maintain this positive momentum by improving staff knowledge of the customers and their business, risks and challenges. This is being done by use of customer profile posters, customer profiles in divisional newsletters, inclusion of customer information in staff training and having Operating staff representation at customer meetings.

Hydro One continues to pursue areas of improvement in communication clarity, promptness, and relevance, as all are key drivers of satisfaction.

5. RELIABILITY PERFORMANCE

While equipment unavailability doesn’t necessarily lead to interruptions due to the redundancy on Hydro One’s transmission system, it is a leading indicator of future reliability erosion. Equipment reliability risk similarly is an indicator of the potential for future reliability issues. Reliability risk provides a comparable illustration of the potential for reliability issues over time. This can be contrasted with reliability performance, as defined by T-SAIDI and T-SAIFI, which are the results of experienced interruption issues. Reliability risk assessment is a proactive measure to mitigate risks before reliability performance starts to deteriorate and negatively impact customers.

Transmission Reliability Performance was the most frequently and consistently mentioned need raised by Customers across all the customer engagement activities found in Exhibit B1, Tab 2, Schedule 2. Customers identified that any degradation of Hydro One’s current level of reliability performance is unacceptable. CEA measures indicate Hydro One is currently in the leading level for multi-circuit performance as shown in Figures 20 and 21 of the Total Cost Benchmarking Study found in Exhibit B2, Tab 2, Schedule 1. Additional metrics relating to Hydro One’s level of reliability can be found on the proposed transmission scorecard found in Exhibit B2, Tab 1, Schedule 1.

5.1 Transmission Reliability

Hydro One measures and actively monitors equipment performance and delivery performance. The equipment performance perspective enables Hydro One to assess the operational performance of transmission components, ensuring that transmission equipment is functioning effectively according to its design. The delivery performance perspective establishes a measure of how reliably electricity is delivered to transmission customers, such as Local Distribution Companies and End Users, in addition to the Hydro One distribution system. Hydro One strives to achieve a high level of performance in the area.

Transmission reliability is determined using measures developed collaboratively with other transmission utilities across Canada at the Canadian Electricity Association (CEA). These measures have been widely adopted since they are well defined and understood by the participating member utilities. The metrics are sufficiently precise and consistent over time to allow them to be used in trended and multi-jurisdictional transmission performance comparisons.

5.2 Transmission Reliability Measures

Hydro One's service reliability includes a set of transmission system equipment performance and electricity delivery performance measures. Three measures listed in Table 1, generally apply to the Delivery Point interfaces between Hydro One's transmission system and its load customers. Delivery Points are either (a) low voltage buses at Hydro One-owned step-down transformer stations[1], or (b) stations owned by transmission load customers, including Hydro One distribution stations and directly-connected transmission end users.

Delivery reliability is measured by frequency of delivery point interruptions, duration of delivery point interruptions and delivery point unreliability index which is a normalized measure of estimated unsupplied energy to customers. All interruptions caused by forced outages are included in these measures. For an indication of transmission equipment reliability performance, transmission system forced unavailability is used.

Table 3: Transmission Reliability Measures

Perspective	Measure	Description
Reliability of Delivery of Electricity to Customers	*Frequency of Delivery Point Interruptions*	average number of interruptions experienced at delivery points due to forced interruptions
	Duration of Delivery Point Interruptions	average interruption durations in minutes experienced at delivery points due to forced interruptions
	Delivery Point Unreliability Index – a measure of unsupplied energy	energy not supplied to customers caused by forced interruptions, normalized by system peak load and presented in System Minutes
Performance of Transmission Equipment	*Transmission Equipment Unavailability*	extent to which transmission equipment is not available due to forced outages

[1] There are situations that a customer owns low voltage buses but these buses are still treated as Hydro One's transmission Delivery Points.

Hydro One's rationale for employing these measures is as follows:

- These metrics are commonly used transmission reliability measures in the industry, especially in Canada. As a group, the measures address transmission service reliability, which is important to customers and stakeholders.
- The benchmarking of these measures is meaningful since the data collecting and reporting practices among all CEA member utilities is consistent as it has been developed and refined over time.
- These measures have been in place for over ten years, which facilitates internal performance trending, setting targets and external benchmarking.
- The limited number of measures keeps tracking and reporting requirements at a manageable and cost-effective level, while still covering a broad transmission reliability performance spectrum.

A summary of delivery point performance according to the Hydro One Customer Delivery Point Performance (CDPP) Standards is discussed in Section 5.4. The standard, attached as Attachment 1, is a Hydro One document previously filed with and approved by the OEB: Customer Delivery Point Performance (CDPP) Standard, EB-2002-0424. Additionally, Attachment 2 provides definitions and detailed descriptions of the reliability measures used in this evidence.

5.3 External Comparisons of Reliability

Using data collected by the CEA, Hydro One is able to compare the reliability performance of its transmission system against the Canadian Transmission Utility average performance. The comparison of delivery point reliability performance is done at the system level, reflecting the system average of all delivery points. Below the system level, Hydro One also focuses on multi-circuit supplied delivery point performance, which is also benchmarked with comparable Canadian utilities.

Hydro One's comparative reliability performance at the system level is illustrated in the following Figures:

- Figure 8a - frequency of momentary interruptions
- Figure 8b - frequency of sustained interruptions;
- Figure 9 - overall frequency of interruptions; ;
- Figure 10 - duration of sustained interruptions; and
- Figure 11 - delivery point unreliability index.

Special notes for July 8th, 2013 GTA rain flooding event:

Due of the significance of customer impact, the July 8th GTA rain flooding event falls into the "Degree 4 Severity" event category, based on the CEA reporting criteria. The criterion indicates that a local disturbance event will be treated separately when the total unsupplied energy caused by the event is more than 1 million MW-minutes. An estimated 1,406,218 MW-minutes (estimated) of unsupplied energy resulted from this July 8th event. The CEA generated two sets of numbers, with and without the event for load interruption related reliability measures. This normalization makes the performance comparison more meaningful among member utilities. The only two other events in the same category in the CEA transmission reliability reporting history were the 1998 Eastern Ice Storm and the 2003 Blackout. In order to have a meaningful comparison, all interruptions due to the July 8th event are excluded from the comparisons presented in this evidence.

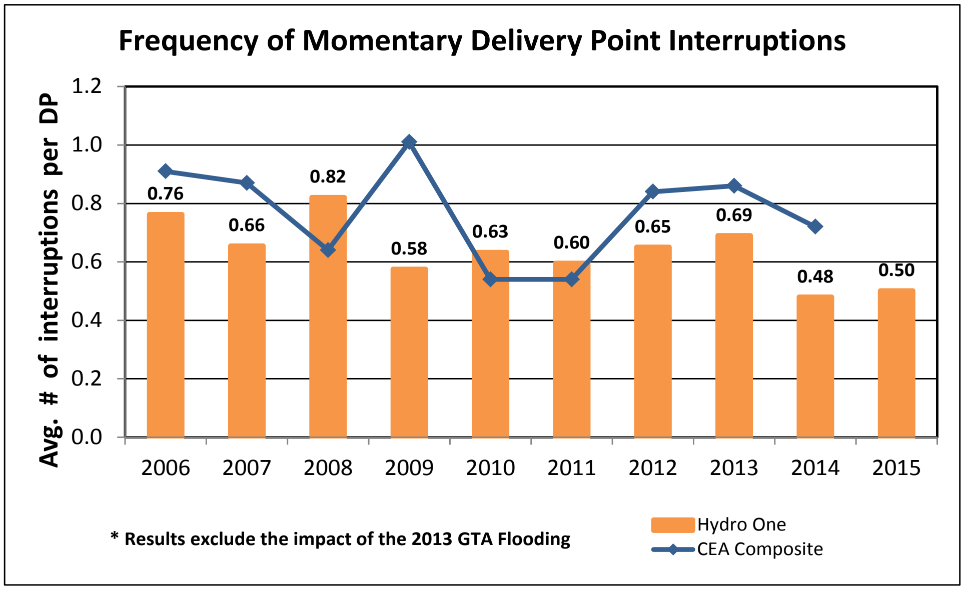

Figure 8a: Comparison of Hydro One Frequency of Momentary Interruptions to CEA Composite

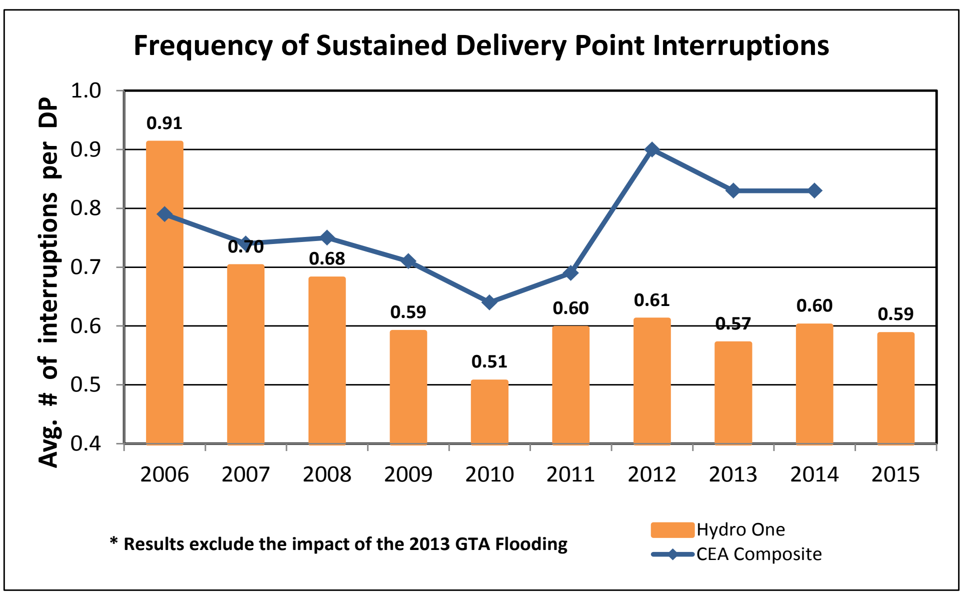

Figure 8b: Comparison of Hydro One to Frequency of Sustained Interruptions to CEA Composite

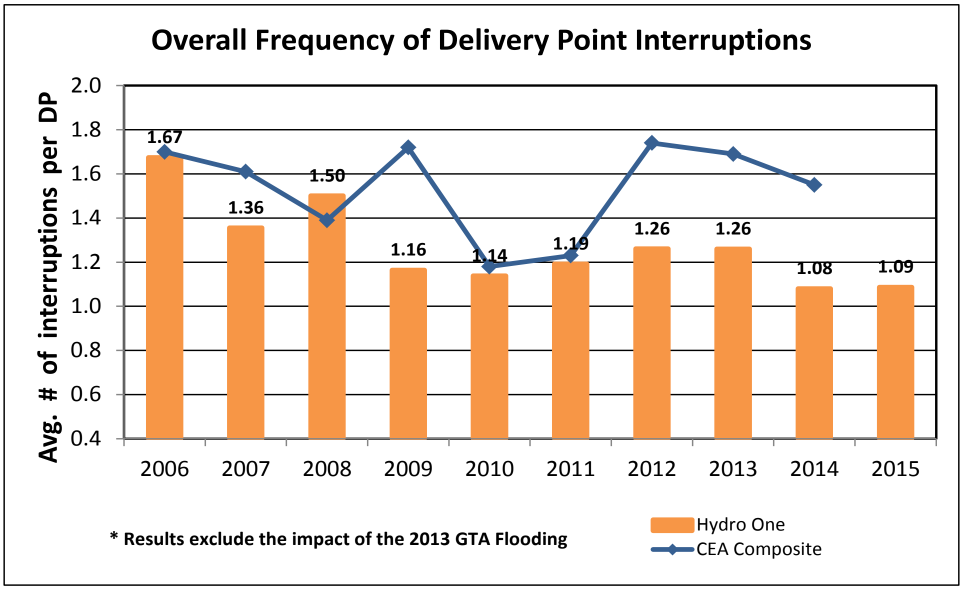

Figure 9: Comparison of Hydro One Overall Frequency of Interruptions to CEA

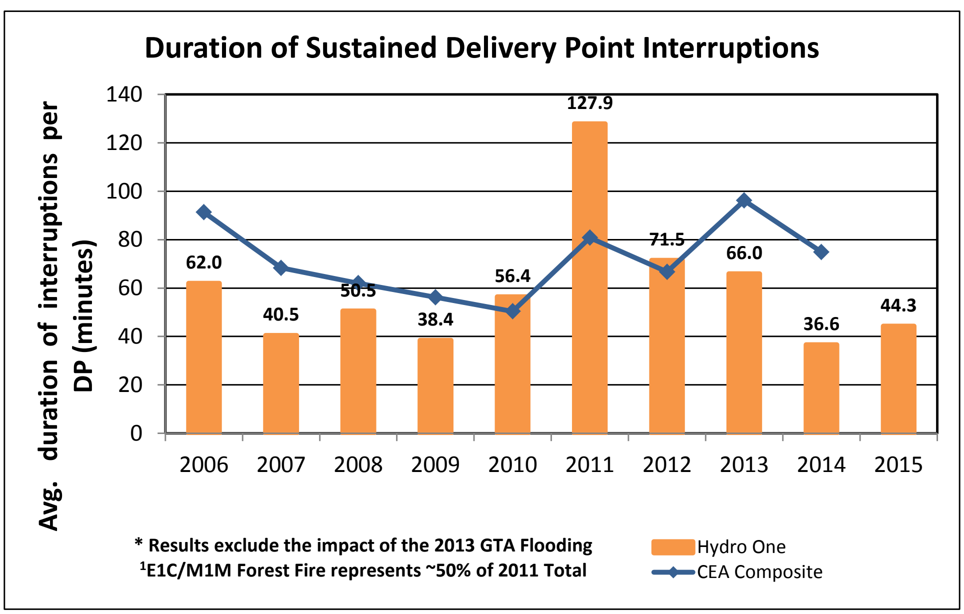

Figure 10: Comparison of Hydro One Duration of Sustained Interruptions to CEA Composite

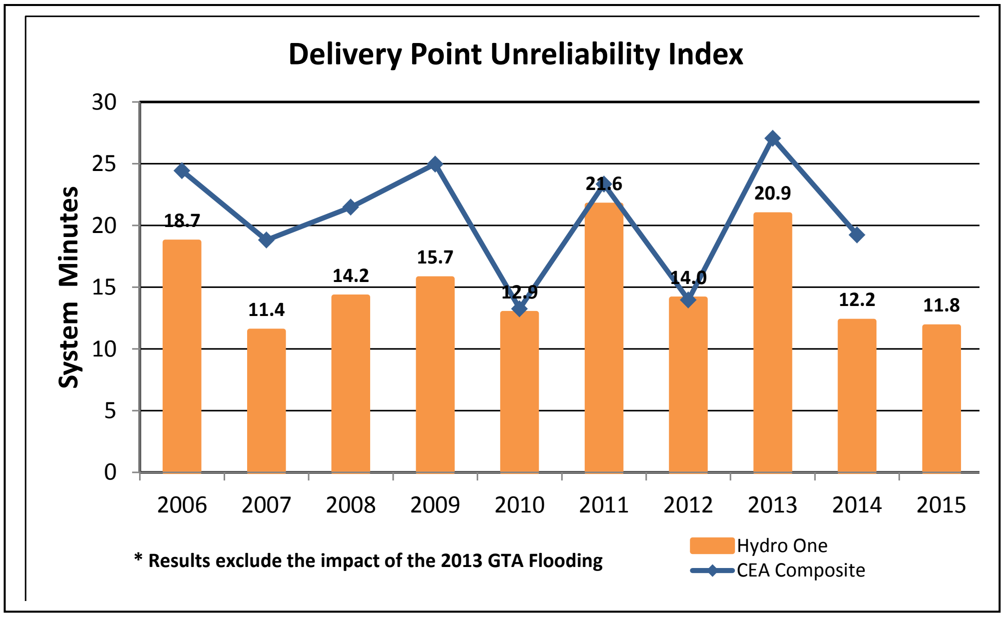

Figure 11: Comparison of Hydro One Delivery Point Unreliability Index to CEA Composite

In this evidence, transmission system forced unavailability is divided into Unavailability of Transmission Lines and Unavailability of Transmission Station Equipment. This is based on the different characteristics of the equipment. Station equipment includes power transformers and circuit breakers, etc. The Unavailability measure represents the extent to which the major transmission equipment is not available for use within the system due to forced outages. The detailed description of this measure is provided in Attachment 2 for both Major Transmission Station Equipment and All Transmission Lines. Figures 12 and 13 illustrate historical performance of Hydro One lines and station equipment in comparison to the CEA Composite five-year moving average performance of all the CEA member utilities.

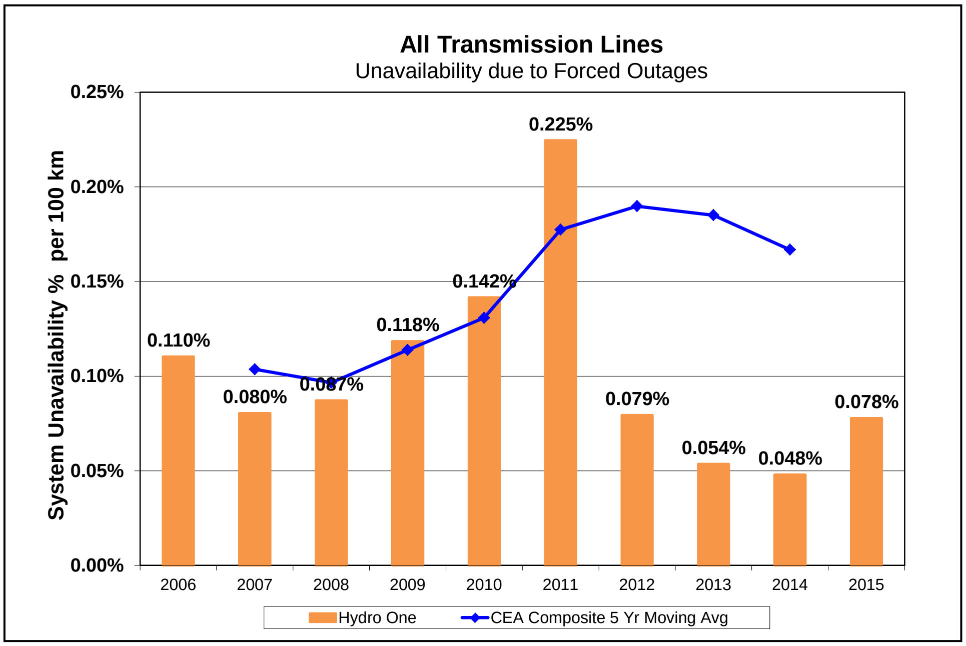

Figure 12: Unavailability of Transmission Lines

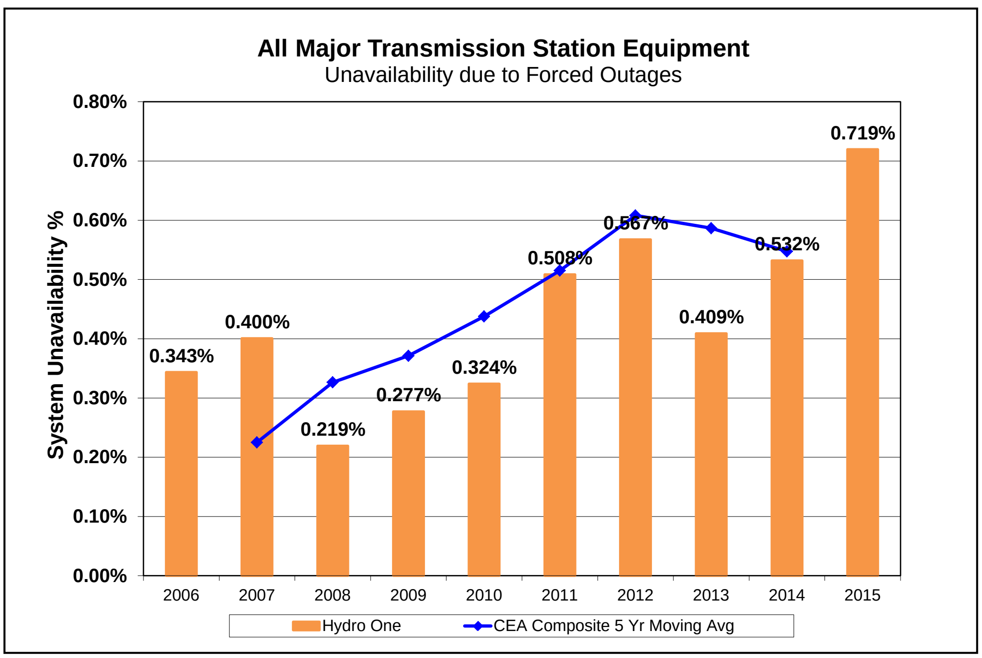

Figure 13: Unavailability of Major Transmission Station Equipment

Equipment performance is a leading indicator of future system reliability. By the time system reliability has measurably degraded, equipment performance will have deteriorated and a significant increase in asset level investment to return to historical reliability levels is required. Sustainment investments are made to preserve performance of critical asset groups by evaluating assets at both an individual asset level and at a station or line level. This prioritizes investment needs to identify the most effective reliability alternative. This approach helps preserve overall system reliability.

Hydro One undertakes an annual detailed assessment of the cited performance measures. This assessment is taken into account along with other factors (such as asset condition) when establishing and prioritizing operating, maintenance and capital programs. For further details see Exhibit B1, Schedule 2, Tab 7, Developing the Investment Plan.

5.4 Delivery Point Performance Outliers

Delivery point performance is evaluated according to the Customer Delivery Point Performance (CDPP) Standard that Hydro One developed, filed with and subsequently approved by the Board in EB-2002-0424. The performance standard is used as a trigger to initiate assessment and follow up with affected customers to:

- Determine the root cause of unreliability;
- Perform technical and financial evaluations; and
- Decide on remedial action to improve reliability.

Figure 14 is a summary of the transmission Group and Individual Customer Delivery Point Performance Outliers as determined by the CDPP Standard criteria from 2007, the first year of formal CDPP reporting.

Note: The Group and Individual CDPP Standard criteria are not mutually exclusive. A delivery point can be both a group outlier and an individual outlier in same year.

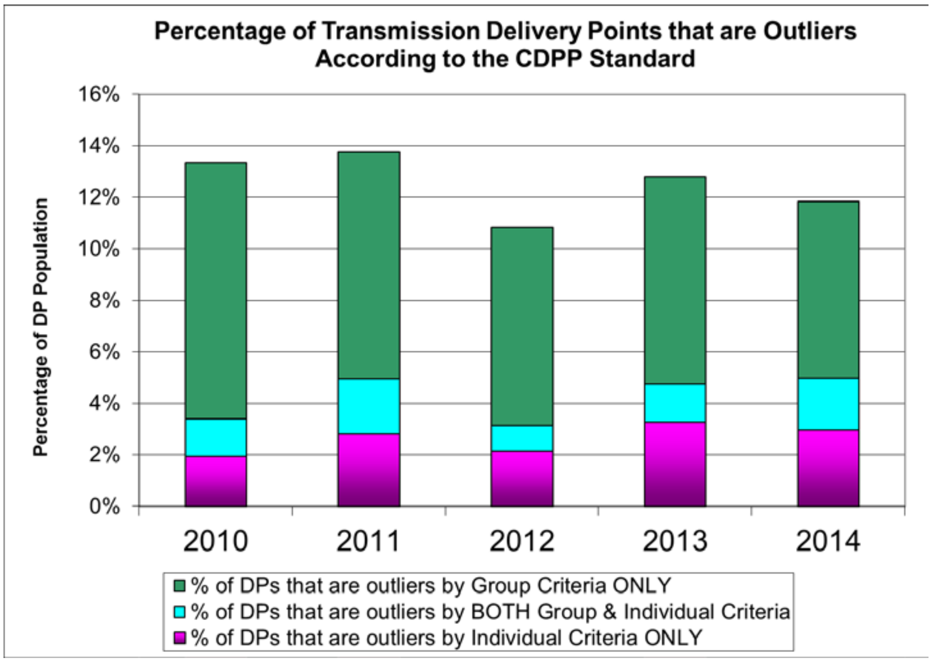

Figure 14: Transmission Load Delivery Point Performance Outliers

The delivery point outliers are analysed and considered for incorporation into future investment programs. Hydro One endeavours to keep the number of outliers at 10% or less of the total population of its delivery points. However, this will not always be the case. Some delivery points are flagged as individual outliers even though they normally experience better reliability performance than the group outlier standard. For example, an individual delivery point may enjoy better performance than the relevant group standard, but, given its extremely good individual outlier (historical) baseline, recent isolated events may drive a decline in specific delivery point performance. This could result in the delivery point temporarily becoming an individual outlier, but in many cases the delivery point could return to non-outlier status in the following year without the need for any incremental investment. Hydro One takes this status into consideration in its assessments.

ATTACHMENT 1 - CUSTOMER DELIVERY POINT PERFORMANCE (CDPP) STANDARD

1. INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop performance standards at the customer delivery point (“CDPP”)[1] level, consistent with system wide standards, that:

- reflect typical transmission system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, load, and capacity levels;
- establish triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken; and
- establish any circumstances in which the performance standards will not apply.

[1] A Delivery Point is defined as a point of connection between a transmitter’s transmission facilities and a customer’s facilities.

On May 3, 2002, Hydro One filed proposed Customer Delivery Point Performance Standards to meet the requirements of the TSC with the OEB for review and approval. Subsequently, on September 8, 2004, as a result of stakeholder comments received, Hydro One filed amendments to its original CDPP Standards submission. On July 25, 2005, the OEB issued its Decision and Order (RP-1999-0057/EB-2002-0424) which approved Hydro One's proposed CDPP Standards subject to a number of changes directed by the Board.

The approved CDPP Standards apply to all existing transmission load customers (including customers that have signed a connection cost recovery agreement prior to market opening). For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement.

2. DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components;

- Group CDPP Standards that relate the reliability of supply to the size of load being served at the delivery point; and
- Individual CDPP Standards that maintain a customer's individual historical delivery point performance.

Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unreliability and remedial action required to improve reliability. The CDPP Standards and triggers for each component are summarized in Sections 2.1 and 2.2.

2.1 Performance Standards Based on Size of Load Being Served: Group CDPP Standards

The CDPP Standards and the associated triggers are based on the size of load being served. For this purpose, the load is the delivery point's total average station gross load[2] as measured in megawatts. The CDPP Standards vary with the size of the load in groups or bands of 0 to 15 MW, greater than 15 up to 40 MW, greater than 40 up to 80 MW and greater than 80 MW, as shown in Table 1.

Table 1: Customer Delivery Point Performance Standards Based on Load Size

Performance Measure	Customer Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		>15 - 40 MW		>40 - 80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

These CDPP Standards are based on historical 1991-2000 performance, as measured by the frequency and duration of all momentary and sustained interruptions[3] caused by

[2] Total Average Station Gross Load (MW) = (Total Energy Delivered to the Station (MWh) + Total Energy Generated at the Station Site (MWh)) / 8760 hours.
[3] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Hydro One components causing load loss. Interruptions caused by Hydro One's customers are recorded but not charged against Hydro One's reliability performance for the customer initiating the interruption, but are charged against Hydro One's reliability performance for other interrupted customers.

forced outages, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system. Included in this category of excluded events are the 1998 ice storm and the 2003 blackout.

2.1.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Group CDPP Standards

The minimum CDPP standards of performance, for each of the four load groups or bands, are used as triggers by Hydro One. The trigger occurs when the three-year rolling average of the delivery point performance falls below the minimum CDPP Standard for the delivery point of the load size group or band (referred to as a performance outlier or outlier) or when a delivery point customer indicates that analysis is required. When an outlier is identified, it is considered a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations in consultation with affected customers to determine the root cause of the unreliability and any remedial action required to improve the reliability.

2.1.2 Performance Standards to Maintain Historical Delivery Point Performance Individual CDPP Standards

In this component, the CDPP Standards are intended to maintain the reliability performance levels at each customer delivery point. This is done by identifying customer delivery points with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1). In order to identify customer delivery points with deteriorating trends in reliability performance, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is established for each delivery point based on that delivery point's historical 1991-2000 average performance, plus one standard deviation (the "historical baseline"). The historical baselines exclude outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical trend of the measure (such as the 1998 ice storm, the 2003 blackout and the GTA Flood in 2013). Also, for delivery points that came into service after 1991, the in-service year is to be the first year of the 10-year period used to determine the performance baseline.

2.1.3 Criteria for Minimum Standard Performance to Identify Performance Outliers for Individual CDPP Standards

Delivery point performance that is worse than the historical baseline (for either frequency or duration) in two consecutive years is considered to be a performance outlier and a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and the remedial measures required to restore the historical reliability of the delivery point's performance.

2.1.4 Remedial Costs to Address Group and Individual Performance Outliers

For Group and Individual Performance outliers, Hydro One will cover the remedial costs of restoring and sustaining the inherent reliability performance of the existing assets to what was designed originally. These costs include appropriate asset sustainment costs, on-going maintenance costs and costs associated with asset refurbishment or replacement. These expenditures are made on an ongoing basis consistent with "good utility practices" irrespective of actual delivery point performance or whether a delivery point is a performance outlier. No customer contribution formula is required for these normal sustainment expenditures.

For Individual Performance outliers, Hydro One will restore the delivery point to the historical level of performance. Hydro One's remedial work will not include capital reliability improvements that significantly enhance the reliability of supply relative to the reliability that was inherent to the original system design or configuration of supply.

For Group Performance outliers, Hydro One's level of incremental investment for improving the performance of an outlier beyond what was designed originally will be limited to the present value of three years' worth of transformation and/or transmission line connection revenue[4] associated with the delivery point. Any funding shortfalls for improving delivery point reliability performance will be contributed by affected delivery point customers. In cases where specific transmission facilities are serving two or more customers in common with outlier performance, Hydro One will approach all affected

[4] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as a proxy in the revenue calculation.

customers to determine their willingness to contribute jointly to the reliability improvements.

Cost responsibility for these investments is to be consistent with the TSC, specifically:

1. Hydro One will not attribute the costs associated with network investment to any customer and any variance from this approach requires a determination by the Board;
2. The costs of preparing the final estimate for reliability improvements required to address performance outliers is the only portion of the technical and financial evaluation that is to be included as part of the cost of the remedial work; and
3. Where a customer contribution is required to improve or expand the transmission system to correct outlier performance, the customer will be given contracting privileges consistent with those applicable to contestability for new customer connections. In addition, affected delivery point customers are responsible for all of the costs associated with any new or modified facilities required on lines and stations they own to improve reliability. These financial and cost sharing arrangements are to be detailed in a connection and cost recovery agreement with the affected customers.

2.2 Process Timelines to Address Performance Outliers

The process and associated timelines that will be followed to address performance outliers– both for Group and Individual outliers – and to determine the preferred course of action, are provided in Figure 1.

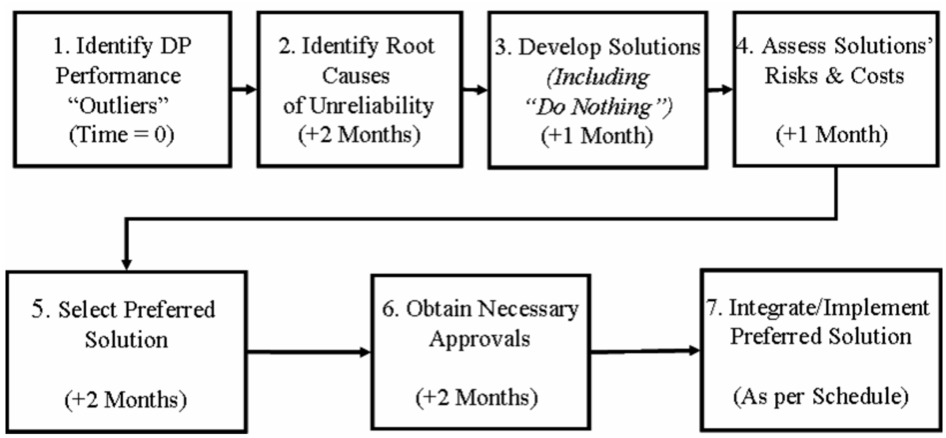

Figure 1: Performance Outlier Process Map

Table 2: Performance Outlier Process

Step	Timeline	Action
1	0	Hydro One identifies, annually, delivery point performance “outliers” for both Group and Individual standards. Hydro One will notify customers that are supplied from these performance outlier delivery points and solicit their feedback/issues/concerns on their reliability of supply.
2	< 2 months	Hydro One will determine the root causes of unreliability associated with each performance outlier identified in (step 1).
3	< 1 month	Hydro One will develop solutions to address performance outliers, including; (i) the work to restore and sustain the inherent reliability performance of the existing assets to what was designed originally; and (ii) for Group Performance outliers, the additional capital improvements required to improve the performance of an outlier to within standard and beyond what was designed originally. Hydro One will discuss the proposed solutions with affected customers.
4	< 1 month	Hydro One will determine the costs and assess the risks of the solutions, including any customer capital contributions required for option (step 2) above. Hydro One will present these costs to customers for their review and assessment.
5	< 2 months	Hydro One and customers select the preferred option and where appropriate customers state their intention on whether to proceed with capital improvements that involve customer contributions identified in option (step 2) above.
6	< 2 months	Hydro One and customers obtain the necessary approvals to proceed with the preferred solutions to address performance outliers.
7	Agreed to Schedule	Hydro One will integrate the solutions into its work programs and implement them according to a mutually agreed schedule.

When Hydro One completes work to restore delivery point performance to standard, it continues to monitor the delivery point the year after the work is completed. If future performance suggests that the standard has not been met, then Hydro One will review the work that has taken place and will identify corrective action. Hydro One will not, as a practice, wait another three years and start a new technical and financial evaluation. Hydro One reviews and identifies customer delivery point performance annually, regardless of the investment history.

ATTACHMENT 2 - DESCRIPTION OF THE RELIABILITY MEASURES

Delivery Point

The delivery point is the point of supply where the energy from the Bulk Electricity System (115 kV and above) is transferred to the Distribution System or the retail customer. This point is generally taken as the low voltage bus at step-down transformer stations. For customer-owned stations supplied directly from the Transmission System, this point is generally taken as the interface between utility-owned equipment and the customer's equipment.

Forced Interruption

A Delivery Point interruption due to the disconnection as a result of an unplanned event.

Planned Interruption

A Delivery Point interruption due to the disconnection at a selected time for the purpose of construction/preventive maintenance.

Momentary Interruption

Any loss of supply voltage to a delivery point that has a duration of less than one minute. These are interruptions generally restored by automatic reclosure facilities and are of very short duration (of the order of a few seconds).

Sustained Interruption

Any loss of supply voltage to a delivery point that has a duration of one minute or more.

<u>Average Frequency of Delivery Point Interruptions</u>

Average Frequency of Delivery Point Interruptions is an indicator of the average number of interruptions that customer experienced and presented as interruptions per delivery point per year. It is expressed mathematically as:

$$\textit{Average Frequency of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}(M_i + S_i)}{N}$$

Where:

- M_i is the total number of momentary interruptions experienced at Delivery Point i in a given year.
- S_i is the total number of sustained interruptions experienced at Delivery Point i in a given year.
- N is the equivalent total number of delivery points for a given year.

The frequency of power supply interruptions and indicators that track such performance are universally used in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden used an interruption frequency indicator. Additionally, the Canadian Electricity Association (CEA) tracks the frequency of delivery point interruptions among the CEA transmission member utilities.

<u>Average Duration of Delivery Point Interruptions</u>

Average Duration of Delivery Point Interruptions is the average time that customers are interrupted from transmission system and presented as minutes per delivery point per year. It is expressed mathematically as:

$$\textit{Average Duration of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}(\mathrm{D}_i)}{N}$$

Where:

- D_i is the total effective interruption duration of Sustained Interruptions experienced at Delivery Point i in a given year.
- N is the equivalent total number of delivery points for a given year.

The duration of delivery point interruptions and indicators that track such performance are universally used in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden used an interruption duration indicator. Additionally, the Canadian Electricity Association (CEA) tracks the duration of delivery point interruptions among the CEA transmission member utilities.

Unsupplied Energy

Unsupplied Energy is an indicator of total energy not supplied to customers due to delivery point interruptions. In order to make it comparable among different sizes of utilities, the unsupplied energy is normalized by the system peak. This measure is defined as Delivery Point Unreliability Index (DPUI). It is expressed mathematically as:

$$\textit{Delivery Point Unreliability Index} = \frac{\sum_{i=1}^{N} U_i \ x\ 60\,\text{min/hr}}{Pk}$$

Where:

- U_i is the total unsupplied energy, expressed in MWh, at Delivery Point i in a given year.
- Pk is the system peak load in the year, expressed in MW.
- N is the equivalent total number of delivery points for a given year.

The unit of the measure of normalized unsupplied energy is expressed in "system minutes". Transmission companies in Canada, the U.S., and Europe use indicators of this type to assess transmission system reliability.

<u>Transmission System Unavailability</u>

Transmission System Unavailability captures the total duration of transmission equipment out of service due to forced outages. Transmission System Unavailability due to forced outages is sub-categorized as (1) Transmission Line Unavailability, and (2) Station Equipment Unavailability, which are consistent to CEA reliability benchmarking programs.

These indicators are expressed mathematically as:

(1) Transmission Line Unavailability $= \left(\dfrac{\sum_{i=1}^{N_L} F_{L_i}}{\mathrm{T_L}} \right) \mathrm{x}\, 100\%$

Where:

- F_{Li} is the annual forced outage duration in hours due to transmission line-related outages of circuit L_i.
- T_L is the inventory (expressed in 100 km-hours) of all in-service transmission circuits.
- N_L is the total number of in-service transmission circuits

(2) Station Equipment Unavailability $= \left(\dfrac{\sum_{i=1}^{N_S} F_{S_i}}{\mathrm{T_S}} \right) \mathrm{x}\, 100\%$

Where:

- F_{Si} is the annual forced outage duration in hours for Major Transmission Station Equipment S_i.

- Ts is the inventory (expressed in hours) of all In-service Major Transmission Station Equipment
- N_s is the total number of in-service major transmission station equipment.

These indicators track the extent to which the transmission system, including transmission circuits and substation equipment, is not available for use. These indicators are focused on the aspect of transmission service within Hydro One's control. It also puts the impact of outages in context with the availability of the transmission system as a whole and expresses the impact of outages in a single, easily understood indicator. Transmission companies in Canada, U.S., and in Europe use indicators of this type to assess transmission system reliability.

HYDRO ONE'S INVESTMENT PLANNING PROCESS: AN OVERVIEW

1. INTRODUCTION

At Hydro One, investment planning is performed annually and consists of the steps illustrated in Figure 1.

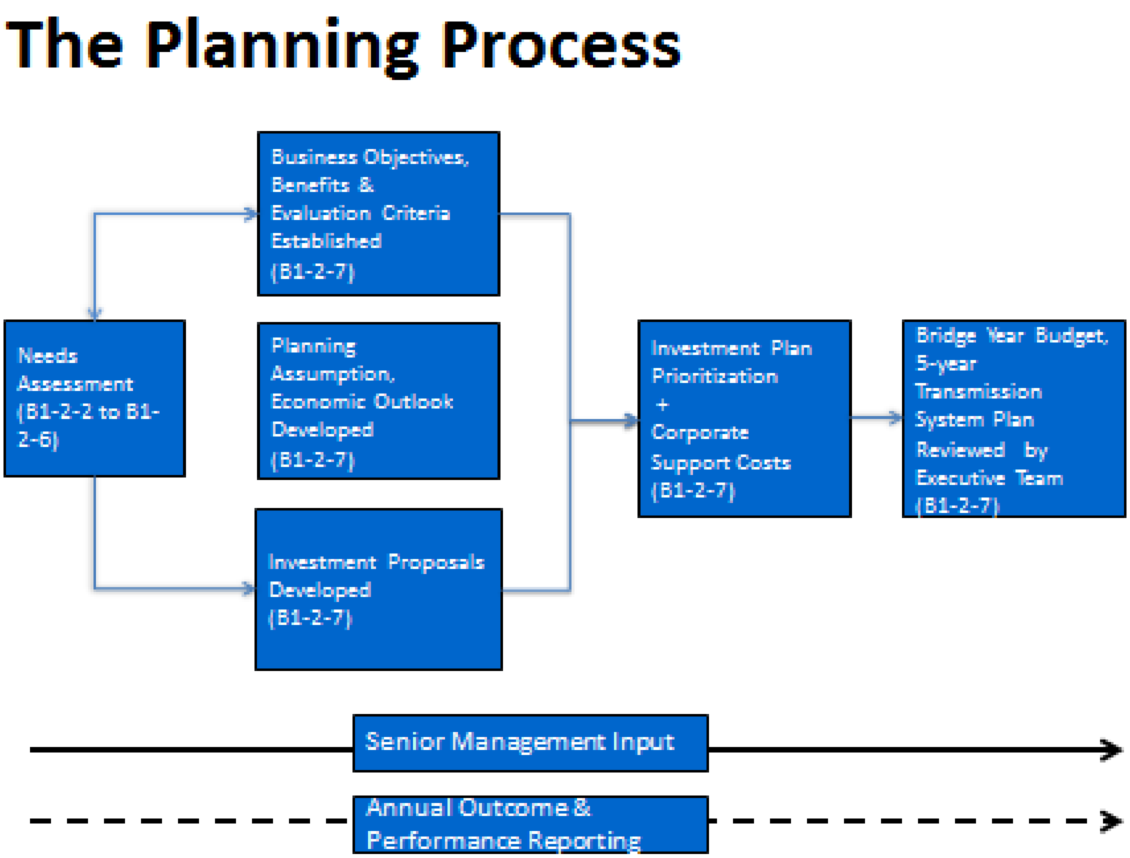

Figure 1

Part Two of the Transmission System Plan describes this process.

2. NEEDS ASSESSMENT

Planning begins with an assessment of investment needs. Exhibit B1, Tab 2, Schedule 2 explains how Hydro One identifies the needs and preferences of its customers through a variety of customer engagement activities. Exhibit B1, Tab 2, Schedule 3 describes how Hydro One identifies system-level needs through the regional planning process.

Exhibit B1, Tab 2, Schedules 4 to 6 describe how Hydro One determines its asset needs. These schedules describe: (a) Hydro One's approach to asset management, which is informed by Hydro One's new system reliability risk model; (b) the asset risk assessment methodology that Hydro One uses in determining which assets are investment candidates; and (c) Hydro One's analyses of the assets that require investment based on asset condition and performance.

3. INVESTMENT PLAN DEVELOPMENT

Exhibit B1, Tab 2, Schedule 7 sets out the investment planning process that takes identified investment needs, turns them into candidate investments, and then feeds them into a prioritization process that yields an investment plan. It describes the considerations that are used to prioritize investments, including the consideration of alternatives, and the managerial oversight of the process. Exhibit B1, Tab 2, Schedule 7 explains that, once Hydro One's executives have approved the investment plan, individual investment proposals in the investment plan are then subject to further scrutiny prior to being released into the execution phase.

IDENTIFYING CUSTOMER NEEDS

1. INTRODUCTION

This Exhibit describes the customer engagement activities Hydro One undertakes to determine its customers' needs and preferences, which inform its Transmission System Plan or investment plan and business objectives.

Hydro One's objective is to engage with customers more consistently and proactively, leveraging a better understanding of the customer to better meet their needs and improve overall satisfaction with their service. One critical element of achieving this goal is developing an investment plan that is outcome-focused and designed to meet customers' expectations.

On a regular basis, as part of its everyday operations, Hydro One engages with customers, collecting information on customer needs and preferences. For the purposes of developing the investment plan set out in this Application, Hydro One has undertaken a customer engagement, as is described in section 2.4 of this Exhibit, that is consistent with the OEB's RRFE framework. The company found the feedback from these sessions to be helpful in understanding customer preferences and being better able to identify customer needs.

Customers indicated that the consultations were valuable to them as well, by contributing to their understanding of Hydro One's operations and investment process. Hydro One intends to continue engaging with customers to receive input for future investment plans and to communicate key information about the transmission system and impacts of its investments.

2. HOW HYDRO ONE ASCERTAINS CUSTOMER NEEDS AND PREFERENCES

As described below, regular communications with customers are conducted through Hydro One's customer business relations group, the OGCC's customer operating support group, customer account executives, and planning activities undertaken by its asset managers.

2.1 Routine Communications

Consistent with the Transmission System Code, Hydro One groups customers into three customer segments: large industrial end users, LDCs and transmission-connected generators.

The "Key Accounts Management" group (formerly, "Customer Business Relations") provides a single point of contact for customers for all types of interactions other than real-time operations, operating events and outage planning. The latter activities are managed by the customer operating support group at the OGCC.

Key Accounts Management facilitates direct communications with customers on a variety of matters including: customer connection requests, sustainment plans and projects, system development plans and concerns regarding service level or power quality. One of the new communication initiatives undertaken in 2015 involved the preparation and distribution of reliability reports specific to the delivery points that supply transmission customers. These reliability reports provide a history of delivery point performance, operating events and outcomes related to these delivery points, and sustainment plans that will impact these delivery points. Hydro One is incorporating the customer feedback that it receives to improve upon the format and content of its communications.

Account executives meet with customers on a regular basis to ensure that customer needs are identified and discussed, and that action plans are developed to address these needs. If the action plans initiate planning activities that may result in new or modified connection facilities, then the account executives also ensure that customers understand the connection process and related contractual matters, such as feasibility studies, connection cost estimates, and capital cost recovery agreements.

Hydro One's asset managers will also proactively and directly engage with customers to review and coordinate plans for the company's assets, in order to minimize impact on the customer and optimize opportunities for both parties to execute work on their respective, affected facilities. The outcomes of these discussions become an input to Hydro One's "transmission system outage grouping" process, which attempts to eliminate multiple outages impacting customer facilities by coordinating activities on the same equipment. Asset managers also engage with customers as part of the regional planning process as documented in Exhibit B1, Tab 2, Schedule 3.

The OGCC has direct communications with customers regarding real-time operations and to coordinate planned outages to enable work by Hydro One or the customer, respond to unexpected outages, and coordinate switching. The OGCC organizes customer meetings bi-annually to coordinate outage planning activities, and such meetings are a key activity in Hydro One's "transmission system outage grouping" process. On a weekly basis, the OGCC sends reports customized to individual customers that provide a rolling one year window of the planned outages that affect their delivery point. These reports contain information on outage start and end dates, the equipment involved, purpose, recall time, and schedule profile. The reports also contain a column for customer comments.

2.2 Hydro One Transmission's Customer Forums

Hydro One also regularly organizes a number of customer forums that facilitate group dialogue to address common specific concerns.

2.2.1 Power Quality Working Group

One such customer forum is the Power Quality Customer Working Group that is made up of Hydro One staff and industrial customers. This group meets on a regular basis to determine processes to identify, diagnose and measure power quality issues. Hydro One has also facilitated two power quality symposiums with an internationally recognized power quality expert to discuss power quality challenges.

2.2.2 Customer Advisory Board

The Customer Advisory Board is organized and facilitated by Hydro One to represent all customer segments on matters relating to customer-impactive policies and services. The board advises Hydro One's management on how to improve services to customers and on the potential customer impacts of the company's policy direction and current initiatives. It includes representatives affiliated with the following associations and groups:

- Association of Major Power Consumers in Ontario;
- Electricity Distributors Association;
- Association of Power Producers of Ontario;
- Consumer's Council of Canada;
- Ontario Federation of Agriculture;
- Canadian Manufacturers and Exporters;
- Vulnerable Energy Consumers Coalition;
- Federation of Ontario Cottagers Associations;

- Small, medium and large LDCs; and
- Large industrial end users.

The Customer Advisory Board meets two times a year to review company initiatives, work program progress, key customer concerns, and proposed asset policies that may affect transmission customers. The mandate of the Customer Advisory Board is being reviewed to further sharpen its focus on customer service.

2.2.3 Large Customer Conference

Annually, Hydro One hosts a conference for large transmission customers and Hydro One's large distribution accounts. At the conference, presentations are given regarding Hydro One's various initiatives, the use of new technology and new challenges such as cyber security. Customers are given an overview and update of Hydro One's investment plan and an opportunity to speak with Hydro One staff on any of the topics in the presentations. The conference content and format are tailored to reflect various customer segments.

2.2.4 Sarnia Area Reliability Oversight Committee

The Sarnia Area Reliability Oversight Committee consists of Hydro One staff and industrial and generation-connected customers in the Sarnia area. The group meets twice a year to identify issues regarding reliability in the Sarnia Area and to review the proposed investment plans to ensure that issues will be addressed appropriately. The industry in the Sarnia area is very sensitive to any type of voltage excursion, which can result in health and safety issues such as gas flares.

2.2.5 LDC Working Group, Toronto-Hydro Oversight Committee

Hydro One also facilitates a LDC working group, which serves as a forum to update LDCs on Hydro One Transmission's policies and practices, identify any emerging issues, and solicit input to enhance customer experience. This group meets three to five times annually.

Hydro One facilitates and participates in bi-monthly Toronto-Hydro Oversight Committee meetings, which serve as a forum for issue identification and resolution to ensure safe and efficient operations between the LDC and Hydro One. These meetings also allow the parties to coordinate their efforts relating to capital projects and other matters.

2.2.6 Switchyard Oversight Committees

Hydro One also facilitates and participates in switchyard oversight committees with Bruce Power Inc. and Ontario Power Generation Inc., which oversee matters of mutual interest related to interface equipment, procedures and policies. These committees aim at supporting the safe and efficient operation of the switchyards in compliance with legal requirements and the coordination of efforts relating to capital projects and other matters. They meet approximately three times annually.

2.3 Customer Survey Research

Hydro One Transmission's customer information input is also obtained through formalized customer satisfaction research. This initiative has been ongoing since 1999. All research is conducted by independent expert consumer research firms. The latest initiative was carried out by Northstar Research Partners Inc., which is described in

Exhibit B1, Tab 1, Schedule 3, together with detailed information on Hydro One Transmission's customer satisfaction performance.

2.4 Customer Engagement Work For The Investment Plan

In the spring of 2016, Hydro One undertook a further customer engagement initiative, the purpose of which was to identify the needs and preferences of customers as it related to the formulation of a five year transmission system plan. This initiative was structured to identify customer needs and preferences and allow for the consideration of those customer needs and preferences in preparing the Transmission System Plan that is reflected in this Application.

Hydro One engaged Ipsos Reid, a global market research company, to assist in the design, execution, facilitation, and documentation of the customer engagement initiative. Ipsos Reid also undertook analysis of the feedback received during the consultations. The report by Ipsos Reid documenting the results of the consultation is included as Attachment 1 to this Exhibit.

2.4.1 Methodology

The customer engagement occurred in three parts. These parts were not sequential; they occurred concurrently. First, one-on-one meetings were held with 12 customers. The materials provided to customers in these consultation meetings are provided in Attachment 2 to this Exhibit. Hydro One segmented and identified the customers for these meetings using the approach described below. Second, Ipsos Reid facilitated five group customer consultations in Toronto, London, Ottawa, Thunder Bay and Sudbury. 22 customers participated in these facilitated group customer consultations. Third, an online consultation tool was made available to all customers, and 28 customers participated. A copy of the online consultation materials is provided in Attachment 3 to this Exhibit.

This three-part process was designed to ensure that all customers had an opportunity to participate in the consultation process and have their voices heard in an effective manner.

Hydro One chose which customers to meet with one-on-one based on a number of criteria:

- the customers represented at least five percent of Hydro One Transmission's overall revenue;
- the customers were among the largest within each sub-segment (i.e. LDCs, large industrial end users, and generators);
- the customers gave a range of scores on 2015 Hydro One Transmission's customer satisfaction survey;
- the customers experienced a range of reliability performance; and
- the customers were geographically diverse.

Further information on the consultation goals, objectives and methodology is included in the Ipsos Reid report included as Attachment 1 to this Exhibit.

2.4.2 Information Presented to Customers

In the consultations, Hydro One presented the following information:

- an overview of Hydro One Transmission's system;
- an overview of a risk-based approach to investments;
- the purpose of Hydro One's customer engagement process (i.e., to identify customers' needs and preferences);
- a description of Hydro One Transmission's system reliability performance;

- the causes of power interruption duration and frequency;
- the types of equipment causing interruptions and their relative contributions;
- an explanation of Hydro One's use of asset demographics and asset condition assessment to identify specific assets at risk;
- a description of actions that Hydro One has undertaken to mitigate reliability risk without increasing investment; and
- a presentation of three illustrative investment scenarios to prompt discussion of acceptable levels of risk compared to investments and potential rates consequences.

The presentation that was shared with customers is provided in Attachment 2 to this Exhibit.

The results of the customer engagement were summarized in the Ipsos Reid report in Attachment 1 to this Exhibit. Attachment 1 to Exhibit A, Tab 9, Schedule 1 contains an overview of these consultations that Hydro One presented to stakeholders on April 27, 2016.

The Ipsos Reid report made the following observations:

- Reliability was the most frequently and consistently mentioned "need" that was raised by customers across all the consultation activities.
- For most large industrial customers, frequency of interruptions is a greater concern than duration. Conversely, LDCs were more likely to say that duration of interruptions is a greater concern than frequency of interruptions.
- Planned outages are considered by many to be much more manageable and less of a concern than unplanned interruptions.
- Overall power quality and transmission capacity were also raised as major issues facing customers, particularly those in the north.

- Cost was raised at various times throughout the consultation. The desire for good reliability at a competitive or low cost is universal.

The detailed report indicates variations on these observations among customer types. For example, LDCs communicated concerns regarding duration of outages, whereas large industrial end users expressed concerns regarding outage frequency. LDCs also expressed that their customers were increasingly expecting fewer to no service interruptions. While the desire for low or competitive costs is universal, sensitivity to rate increases varied between groups.

3. SUMMARY OF CUSTOMER NEEDS AND PREFERENCES

Based on all the information collected during its customer engagement activities, Hydro One believes that:

- Customers need predictable, reliable power at the current level of performance or higher, particularly, with respect to frequency of interruptions, especially large industrial end users who otherwise face unacceptable economic, environmental and health and safety risks;
- Customers prefer competitive or low cost of service, but not at the expense of deteriorated service;
- Customers need improved outage planning and notification (specifically, minimization of the number of planned outages and improved communication);
- Customers expect continuing communication of Hydro One Transmission's long-term investment plans; and
- Customers need a greater focus on power quality driven by the increased sensitivity of their equipment.

4. HOW THE TRANSMISSION SYSTEM PLAN REFLECTS CUSTOMER NEEDS AND PREFERENCES

Hydro One's Transmission System Plan reflects its general assessment of customer needs and preferences. The investment plan takes customer engagement information into account as follows:

- The plan mitigates the risk to current service levels posed by asset deterioration;
- The plan supports Hydro One's ability to continue to provide first quartile reliability in a safe manner; and
- The plan optimizes the life of assets to avoid unnecessary capital expenditures.

The investment plan reflected in this Application seeks to meet customers' needs regarding service levels, in a manner that controls costs to address their desire for low or competitive costs. Hydro One recognises that customers are sensitive to the total delivered price of power. Investments in the transmission system result in increased cost to customers. As such, Hydro One's focus will be on executing cost controls and driving productivity across the organization in order to mitigate rate impacts from required work programs. Hydro One's ability to influence customers' total bills, and customer perceptions of the price of power, is limited by the fact that the transmission tariffs represent less than 10% of an average transmission-connected customer's total bill.[1] Ongoing communications with customers to provide information regarding these facts will be another area of focus for Hydro One during the test years in this Application.

Exhibit B1, Tab 3 describes how the proposed investments address Hydro One Transmission's customers' needs.

[1] Transmission tariffs constitute 8.3% as percentage of total cost for transmission-connected customers, on average.

CUSTOMER CONSULTATION REPORT

DEVELOPMENT OF TRANSMISSION INVESTMENT PLAN

APRIL 2016

Prepared for:

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hydro one

Ipsos Public Affairs

CUSTOMER CONSULTATION REPORT

DEVELOPMENT OF TRANSMISSION INVESTMENT PLAN

APRIL 2016

This report has been prepared by Ipsos for Hydro One Networks Inc. The conclusions drawn and opinions expressed are those of the authors.

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INTRODUCTION

ABOUT THIS CONSULTATION

BACKGROUND AND CONTEXT

Ipsos was commissioned by Hydro One Networks Inc. (Hydro One) to assist with the design, execution, documentation, and analysis of feedback for its transmission-connected customer engagement and consultation process. This process was predicated on the customer engagement activities that were undertaken by Hydro One as part of its processes to develop its 2017-2022 Business Plan and was designed to supplement and complement these activities.

This report documents and summarizes feedback and insight from customers that will be considered by Hydro One as it develops its investment plan to support its Transmission Revenue Requirement and Rate Application for 2017-2018. The Company plans to submit this application on May 31, 2016.

Hydro One's consultation process contemplated the enhanced engagement between utilities and their ratepayers as described in the Ontario Energy Board's (OEB) *Renewed Regulatory Framework for Electricity* (RRFE). The RRFE holds the expectation that utilities "demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate consultation…"[1] The expectation therein; to provide an overview of associated customer engagement and outreach activities in its application, as well as to demonstrate how customer feedback/needs have been reflected and considered, further shaped Hydro One's approach.

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity, October 2012, Section 2.5

By engaging Ipsos, a third-party research firm, the company set out to establish a best-in-class consultation process. Ipsos was engaged to ensure facilitation, the development of research and questions, and the report writing provided an unbiased, unvarnished, evidence-based consultation report to support the filing.

Further, Hydro One's application filing must demonstrate that services are provided "in a manner that responds to identified customer preferences."[2] This was accomplished by providing information on customer engagement to identify:

- Customer preferences;
- The value proposition the plan represents for customers (economic efficiency and cost-effectiveness) as it relates to sustainment-focused investments; and,
- The factors relating to customer preferences, or input from customers and participants in a process that considered preferences in the course of planning investment projects and activities.

CONSULTATION GOALS

- Establish a new, best-in-class approach to customer consultation to allow Hydro One to transition elements of its Cost of Service Application to the RRFE approach;
- Establish an inclusive, accessible, verifiable, and transparent consultation process to secure the input/feedback necessary to prepare an investment plan and Transmission Rate Application that considers Hydro One's customers' needs and preferences; and,
- Ensure the associated customer and stakeholder consultation and feedback is consistent with the OEB's Filing Requirements for Electricity Transmission Applications and the Renewed Regulatory Framework.

CONSULTATION OBJECTIVES

- Establish the process and conditions for effective consultation with transmission-connected customers;
- Ensure that every customer has the opportunity to participate;
- Provide sufficiently detailed plans and illustrative investment scenarios so that the customers can provide informed feedback;
- Take a research-based approach to consultation in order to gather the data necessary to support an informed and representative view;
- Contribute to better and objective analysis of customer input by engaging external research professionals; and,
- Demonstrate flexibility and provide tangible evidence of Hydro One's willingness to listen, learn and establish plans that are informed by the consultation and consider the needs of its customers.

OTHER CONSIDERATIONS FOR CONSULTATION

- Consultation should take place as early as possible to build trust and awareness of the process, and more importantly to allow time for Hydro One to develop plans that consider customer input;
- The process must be professional, well-executed and conducted in a manner that clearly states the aims, rules, and process for all involved;
- It should be understood that all viewpoints are welcome but that consultation may not result in consensus, nor is it intended to result in consensus;
- The process must respect the values and varying interests of all participants; and,
- Participants should represent decision makers or spokespersons for their representative organizations.

[2] Ibid, Section 1.0

DESCRIPTION OF HYDRO ONE

Hydro One is Ontario's largest electrical transmission utility. Its operations cover some of the most challenging and diverse geography in Canada. Hydro One's system transmits electricity from generation sources to transmission-connected customers, and indirectly through them, distribution customers.

Hydro One's transmission customers across Ontario include 47 local distribution companies (LDCs), Hydro One's own distribution system, and 90 large industrial customers directly connected to the transmission system.

Hydro One's transmission system totals 292 transmission stations and 29,000 circuit kilometres of high-voltage lines, towers and transformers, operating at 500 kV, 230 kV or 115 kV. It represents approximately $12B in assets.

Hydro One is accountable to plan, operate, build and maintain an affordable, robust and flexible transmission system that serves Ontario's needs and meets obligations as part of the North American grid.

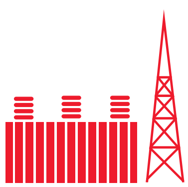
According to Hydro One, its investment plan will identify, prioritize, and schedule the investments made in their system. On this basis, Hydro One has stated that it aims to create value by:

- Ensuring its investment plan considers and reflects the needs and preferences of its customers by achieving a balance between managing risk, service and cost, while recognizing its customers' needs and maintaining a high standard of quality;
- Recognizing that every dollar spent comes at a cost to its customers and the people of Ontario;
- Making prudent, cost-effective, short and long-term investments in the transmission system so that the electricity needs of Ontario are met now and into the future;
- Addressing emerging risks to the system, and always looking for ways to economically extend the life of existing transmission assets; and,
- Being innovative by adapting new/proven technologies, equipment and processes that contribute to the efficiency of the operation.

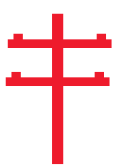
CUSTOMER SEGMENTS

The consultations were designed to reflect the specific segments of transmission-connected customers of Hydro One. Hydro One's transmission-connected customers across Ontario include local distribution companies (LDCs), Hydro One's own distribution system, and large industrial customers directly connected to the transmission system.

All of these customers have significant power requirements. They include:



Generators:
Generators are transmission-connected customers of Hydro One.



Local Distribution Companies (LDC):
OEB-licensed distributors that provide electricity to their residential and business customers.

Large Industrial Businesses:
End-users connected to Hydro One's transmission system.

PART A: CONSULTATION METHODOLOGY

METHODOLOGY AND APPROACH

To provide Hydro One with the feedback required to inform its investment plan, a multi-faceted consultation engagement program was developed. This approach permitted the collection of qualitative insight in three waves: the first wave of one-on-one dedicated meetings with selected customers; the second wave of larger, facilitated group sessions; the third in the form of Ipsos' online consultation tool. Every transmission-connected customer of Hydro One was afforded the opportunity to participate in at least one wave of the consultation.

Regardless of the wave the customer was invited to participate in, all customers were emailed an advance copy of Hydro One's Transmission Consultation Materials, which included three illustrative investment scenarios. These scenarios were illustrative examples of investment plans, each containing details of potential investments in assets and asset classes, the change to the reliability risk profile, the overall capital expenditure required, as well as the incremental difference between scenarios, and corresponding rate increase for each scenario.

The materials have been appended to this report.

WAVE ONE

This wave involved one-on-one meetings with a selected cross-section of transmission-connected customers between March 9, 2016 and April 8, 2016.

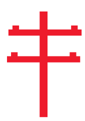
Customers were selected and invited by Hydro One for one-on-one meetings based on a number of criteria:

- The customers represented at least 5 per cent of Hydro One's overall revenue in the transmission-connected customer segment; and,
- Were among the largest customers within each sub-segment (LDCs, large end-users, and electricity generators).

The selected customers represented:

- A range of customer satisfaction scores based on Hydro One's 2015 Transmission Customer Satisfaction Survey (i.e. both satisfied and non-satisfied customers were included);
- A range of reliability performance; and,
- Geographic diversity.

A total of 29 individuals representing 14 customers were selected and invited to Wave One, of which 42 individuals representing 12 customers participated.[3] The 12 one-on-one sessions were conducted at a location convenient to the customer, and included 4 LDCs, 6 end-users (large industrial), and 2 generators.

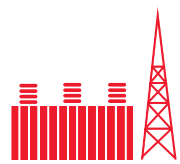


LDCs:

- Veridian Connections Inc.
- Hydro Ottawa Limited
- Thunder Bay Hydro Electricity Distribution Inc.
- Toronto Hydro-Electric System Limited

End-users (large industrial):

- Arcelormittal Dofasco Inc.
- Resolute FP Canada Inc.
- Domtar Inc.
- General Motors of Canada Ltd.
- Nova Chemicals (Canada) Ltd.
- Suncor Energy Inc.



Generators:

- Ontario Power Generation
- Bruce Power L.P.

The following products and feedback mechanisms were developed and used during Wave One:

- Hydro One Transmission Consultation Materials, including three illustrative investment scenarios to provide a launching point for discussion;
- Customer-specific information pertaining to potential investments that may directly affect their organization;
- Note takers present at each session to document comments from all participants; and,
- The opportunity to participate in the Wave Three self-directed Ipsos online consultation tool to supplement the discussion after the one-on-one session.

[3] For some customers, more participants attended the Wave One one-on-one session than those invited by Hydro One. For example, in some cases two individuals representing one customer were invited to participate in the one-on-one session, but three individuals representing the customer arrived on the day and participated in the discussion.

WAVE TWO

This wave represented formal, facilitated, face-to-face larger group sessions that all customers were invited to attend. These sessions were held across the province at convenient locations to allow for maximum customer participation. Sessions took place in Ottawa, London, Thunder Bay, Sudbury, and Toronto between March 16, 2016 and March 24, 2016. Customers were invited to attend the nearest location to them, but were given an opportunity to opt for any location that was more convenient. A total of 263 individuals from 188 customers were invited by Hydro One, of which 33 individuals representing 22 customers attended.[4]

By design the sessions included a mix of customer segments (LDCs, large industrial businesses, and electricity generators) to allow for a richer mix of feedback and opinions, and to promote transparency of potentially divergent views among customers. This allowed participants the unique opportunity to respond to each other during the session.

The following products and feedback mechanisms were developed and used:

- Hydro One Transmission Consultation Materials, including three illustrative investment scenarios to provide a launching point for discussion;
- Online Consultation Tool (Ipsos' Ideation platform); and,
- Note takers present at each session to document comments from all participants.

ABOUT IPSOS AND IDEATION EXCHANGE

Facilitation via Ideation:

Ipsos used its Online Consultation Tool, Ideation Exchange, in order to facilitate the larger consultations. Ipsos Ideation Exchange bridges knowledge, ideas, people, and settings to create an environment for open, participative and aligned collaboration. Used to facilitate brainstorming, integrated thinking, cross functional collaboration, strategic planning and assessment, the Ideation Exchange leverages technology and software to create a high-energy, interactive and efficient alternative to more traditional facilitation approaches.

What was especially powerful in the Ideation sessions was that all participants were active at the same time. The real-time electronic format allowed for simultaneous input from participants and the ability for participants to see the collective input of the others during the session in real-time. The sessions were highly energizing for participants and also created a high-level focus on the outcomes. In short, the tool offered a unique way to get:

- Anonymous, highly collaborative feedback;
- Rapid planning, ideation and prioritization;
- Wisdom of crowds;
- Polling, charting and tabulation of responses in real time;
- Quickly categorized responses;
- Convenience – access anywhere, for broad geographic participation; and,
- Quickly generated transcripts and actionable next steps.

Ideation Exchange is a platform where customers simultaneously contributed feedback in addition to voicing their opinions verbally throughout the session. Each customer had a laptop connected to a network to contribute opinions, preferences and feedback in real-time that was shared with the room. The laptops helped facilitate collaboration but did not replace the need for face-to-face interaction in the sessions. Session facilitators provided expertise in drawing out common themes within the room and encouraging conversation to ensure the highest level of output.

[4] For some customers, more participants attended the Wave Two facilitated group session than those invited by Hydro One. For example, in some cases two individuals representing one customer were invited to participate in the group session, but three individuals representing the customer participated in the session.

SESSION AGENDA

The session was conducted in three parts:

1. Introduction: Context and Objectives

Hydro One representatives provided an introduction to their organization, transmission system, and asset portfolio, and outlined the goals for the session - they would like to ensure that they are reflecting the needs and preferences of their customers; are being prudent and cost-effective; are addressing emerging risks; and are innovating by adapting new/proven technologies.

Hydro One representatives summarized their customer engagement process as it relates to developing their Investment Plan and rate filing, noting such elements as:

- One-on-one discussions with selected transmission-connected customers from all segments – LDCs, large industrial businesses, and generators;
- Larger, professionally facilitated customer engagement sessions held in Toronto, London, Ottawa, Thunder Bay, and Sudbury; and,
- An online consultation tool sent to all transmission-connected customers. The content that was shared and the questions that were posed in the Wave Three online tool were similar to what was provided /asked in the larger consultation sessions via Ipsos' Ideation platform in Wave Two.

2. Review: System Performance

Hydro One representatives detailed Hydro One's System Performance from 2011 to 2015 underscoring that equipment performance is the largest controllable factor affecting reliability; underlying reliability risk is increasing; condition assessments have identified critical replacement needs; and Hydro One continues to take action to mitigate reliability risk.

Hydro One outlined and reviewed:

- The duration and frequency of interruptions broken down by (i) average per delivery point, (ii) multi-circuit and single-circuit system, and (iii) contribution to interruption by cause;
- Which equipment classes are causing interruptions;
- Details and context for age and condition on asset classes;
- Unplanned and planned outage hours caused by equipment failure system-wide; and
- Ongoing activities to address reliability risk.

3. Discussion: Investment Scenarios

Hydro One representatives outlined recent changes that have occurred at their organization – a new President and CEO, new management and an independent Board of Directors, historical benchmarking with other transmission utilities across North America, as well as greater clarity from the OEB on the RRFE as it relates to transmitters.

Hydro One clarified that the information being presented as it related to the company's Investment Plans was not final nor did they have a recommendation – instead, they were looking to better understand their customers' needs and preferences to inform the development of the potential Investment Plan.

Hydro One presented three illustrative investment scenarios. These scenarios were illustrative examples of investment plans, each containing details of potential investments in assets and asset classes, the change to the reliability risk profile, the overall capital expenditure required, as well as the incremental difference between scenarios, and corresponding rate increase for each scenario.

They also clarified that the illustrative scenarios:

- Are flexible;
- Related to Sustainment Capital Expenditures only with Development and Common being a separate line item; and,
- Did not include Operating Investments, and that the forecast rate impacts did not include the impact of OM&A costs, load forecasts, or borrowing costs.

WAVE THREE

It was understood from the outset that not all customers would be able to participate in Wave One or Two sessions. It was clear that it was necessary to provide a third option for providing feedback. Ipsos provided a self-directed form of Ideation Exchange where customers could asynchronously provide feedback on the illustrative scenarios over a one week period. The same Hydro One presentation used in the Wave One and Two sessions and similar questions posed during these sessions were reflected in the self-directed online consultation tool. Customers simply signed into the platform at a time that was convenient for them, and provided self-guided feedback. The feedback from the online tool was then analyzed, along with feedback from the Wave One and Two in-person sessions, and incorporated into the report.

Hydro One invited all transmission-connected customers to participate in Wave Three between March 21, 2016 and March 31, 2016. In total, 292 individuals representing 183 organizations were invited to participate and 37 individuals logged into the online consultation tool. A total of 31 individuals partially or fully answered the list of questions. These 31 individuals represented 28 customers, as well as one individual from the National Research Council of Canada, and one from McMaster University.

Two individuals who participated in Wave Two also answered the Wave Three online consultation tool questions. Their responses and comments in both waves were included as part of the consultation feedback.

The following products and feedback mechanisms were developed and used during Wave Three:

- Hydro One Transmission Consultation Materials, including three potential investment scenarios to provide a launching point for discussion; and,
- Self-directed Ipsos' online consultation tool.

BREAKDOWN OF CONSULTATION PARTICIPANTS

The tables below break down the customers represented in each wave by number of participants and the number of customers represented. A full listing of the names of participants and the customers that they represent has been appended to this report. Multiple participants representing the same customer may have been invited to provide their feedback via the Online Consultation Tool on their organization's behalf.

TOTAL NUMBER OF PARTICIPANTS

	WAVE ONE	WAVE TWO						WAVE THREE
		Thunder Bay	Ottawa	Sudbury	Toronto	London	Total	
LDC	15	0	2	3	9	8	22	10
Large Industrial Business	21	3	0	3	4	0	10	10
Generator	6	0	0	0	0	0	0	9
Other	0	0	0	0	1	0	1	2
TOTAL	42	3	2	6	14	8	33	31

Other includes the Association of Power Producers of Ontario, National Research Council of Canada, and McMaster University.

TOTAL NUMBER OF CUSTOMER ORGANIZATIONS REPRESENTED

	WAVE ONE	WAVE TWO						WAVE THREE
		Thunder Bay	Ottawa	Sudbury	Toronto	London	Total	
LDC	4	0	1	1	7	4	13	9
Large Industrial Business	6	2	0	2	4	0	8	11
Generator	2	0	0	0	0	0	0	6
Other	2	0	0	0	0	0	0	6
TOTAL	12	2	1	3	12	4	22	28

Other includes the Association of Power Producers of Ontario, National Research Council of Canada, and McMaster University.

REPORTING CONVENTIONS

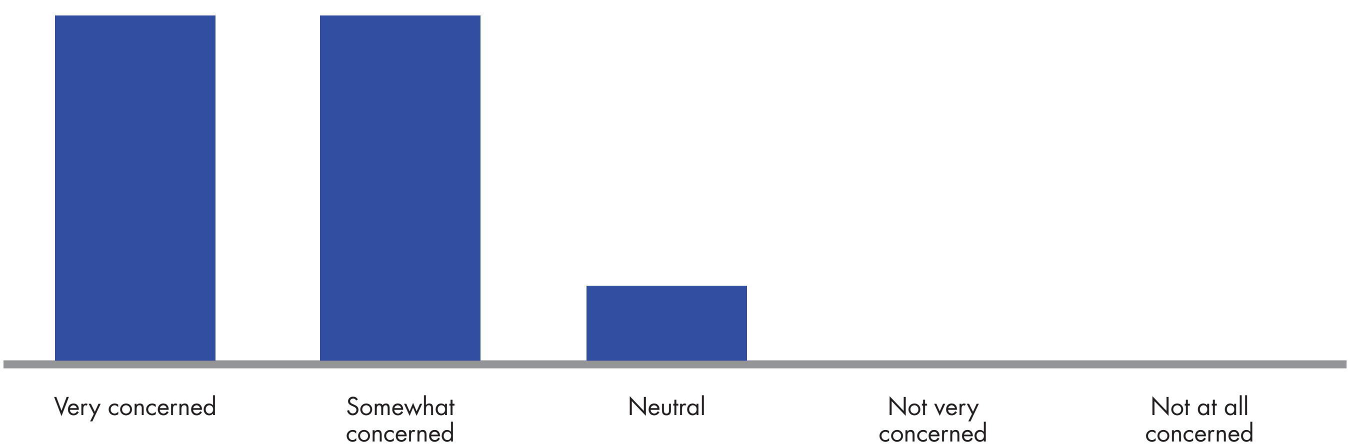
REPORTING OF OPEN-ENDED AND CLOSED-ENDED DATA

Both the discussion guide used in the Wave One and Two consultation sessions, as well as the online consultation tool emailed to customers as part of Wave Three included a combination of open and closed-ended questions. For open-ended questions, all responses, whether provided orally or in written form, were reviewed and summarized in the report. For questions where there was a general sentiment or consensus this has been described as such, and where there was a diversity of comments or opinions these differences are highlighted. Trends in opinions within and between customer segments are highlighted in Part B: Noted Differences by Customer Segment, while comparisons between customers in Northern Ontario and Southern Ontario are also highlighted in Part B: Noted Differences by Geography.

For close-ended questions, such as yes/no or scale questions, all responses were tabulated and reported in aggregate. Since not all participants answered each question, the base size of responses for each question (number of participants who answered) varies from question to question. Where closed-ended data has been reported in chart format, the base size or the number of participants who answered the question is shown at the bottom of the chart. In the example to the right, a total of 40 participants provided an answer to this question. The distribution of the 40 responses across each of the response options is shown in the chart.

Given that the sample sizes are relatively small, it is not appropriate to report the results as percentages. Therefore, we have opted to show the magnitude of the responses to each response option in chart format without indicating the percentage or count of responses.

CONCERN ABOUT RELIABILITY RISK



How concerned are you about system reliability risk?
Base: Wave 2 and Wave 3 participants who responded to the question (n=40)

TERMINOLOGY – INTERRUPTION VS. OUTAGE

Throughout the report the terms interruption and outage are used often. The term interruption refers to a complete loss of electric power and outage refers to the disabling of a component's capability to deliver power (planned or unplanned). An outage may or may not cause an interruption of service to customers. Where a participant used the terms interchangeably or used the terms differently, the report documents them using the above meanings. However participants' verbatim comments shown in the report as a formal quote have not been altered.

EXECUTIVE SUMMARY

CUSTOMER NEEDS AND PREFERENCES

Reliability was the most frequently and consistently mentioned need raised by customers across all the consultation activities. For most large industrial customers frequency of interruptions is a greater concern than duration, whereas Local Distribution Companies (LDCs) were more likely to say that duration of interruptions is a greater concern than frequency of interruptions. Despite these different perspectives, most customers agreed that improvements in both frequency and duration are among their top needs. Planned outages are considered by many to be much more manageable and less of a concern than unplanned interruptions. Overall power quality and transmission capacity were also raised as major issues facing customers, particularly those in the North.

While not the most often mentioned need, cost was raised at various times throughout the consultation. The desire for good reliability at a competitive or low cost is universal. For LDCs, since the transmission rate is a pass-through cost, the primary issue they face is the impact on the ratepayer and some expressed concern that their customers are feeling rate increase fatigue.

The need for greater communication between Hydro One and transmission-connected customers was articulated often throughout the consultation activities. Some customers stated that historically Hydro One's long-term plans were not communicated with them so they have struggled with certain aspects of their own localized or distribution network planning as well as their own asset replacement planning as a result. In general, customers acknowledged that this type of consultation discussion with customers would not have happened 10 years ago and they welcome, if not now expect, the opportunity to hear more about Hydro One's plans for the future.

PRIORITIZATION OF GREATEST CONCERNS WITH HYDRO ONE

Interruptions and rates (specifically rate increases greater than 5%) were mentioned as the top two concerns by the largest share of customers, with adequate asset management and replacement coming in close to the top. Other concerns were acknowledged as being important but interruptions have the biggest impact on productivity and revenue loss. Many customers provided examples of the financial and health and safety impacts of even short interruptions in service. Given these impacts, customers wanted to see Hydro One strike the right balance between reliability and rates.

ADDRESSING RELIABILITY RISKS VS. DEFERRING INVESTMENT

For the most part, customers believe that Hydro One does need to be more proactive in addressing current and emerging reliability risk now. Those that didn't strongly agree with this statement stated that they themselves have not had many transmission interruptions. While there was general acceptance that Hydro One's assets appear to be aged, some stated that they did not have enough information on asset age and performance, or the methodology of condition assessment and maintenance to confidently provide an opinion on the extent to which Hydro One should be more proactive in addressing current and emerging reliability risks now, rather than deferring investments.

RELIABILITY RISK VS. RATES

The majority of customers who participated in the consultation activities indicated that increased reliability risk, particularly at the magnitude of approximately 10% is unacceptable. Most would be willing to support the investment required to at least maintain the current level of reliability risk. The general sentiment, overall, was that the right balance between reliability risk and rates is somewhere between Illustrative Scenario 2 (6.3% rate increase for an essentially unchanged reliability risk) and Scenario 3 (6.8% rate increase for approximately 10% improvement in reliability risk). Based on the scenarios, a marginal improvement in reliability risk (less than 10%) would reflect a rate increase that falls between 6.3% and 6.8%.

A few of the large industrial customers, in particular those experiencing a relatively high number/frequency of unplanned interruptions, were quite clear that in their view Scenario 3 is the required minimum. However, these same customers, as well as others, expect to see an improvement in actual reliability performance, not necessarily only a reduced reliability risk for this level of investment. We consistently heard, across all customers (LDC, generator and industrial) an expectation to see an improvement in their service performance in terms of reliability (fewer unplanned interruptions) as well as power quality.

FEEDBACK ON THE CONSULTATION PROCESS

Overall customers provided positive feedback about the consultation process and several commended Hydro One for engaging in a consultative process for the development of the investment plan.

There was a high level of interest in learning more about Hydro One's system performance, asset age, condition assessments, and the specific actions Hydro One has undertaken and plans to undertake to mitigate reliability risk. Most customers participated actively in the Wave Two sessions posing questions and offering comments spontaneously as well when asked specifically for their opinion.

When asked, most customers agreed that that their feedback was heard. Opinions were divided as to whether the sessions got to the right issues. Those that indicated that the session may not have gotten to the right issues were unsure they received sufficient information from Hydro One to fully form an opinion on Hydro One's illustrative scenarios.

PART B: CONSULTATION INSIGHT

INTRODUCTION – CONTEXT SETTING AND CONSULTATION PROCESS

Customers that participated in the consultation, whether through the in-person consultation sessions of Wave One and Wave Two or the online consultation tool in Wave Three were provided with an introduction to Hydro One – its mission and goals, information on the scope and value of its assets, and the regulators to which they are accountable.

Hydro One then detailed its risk-based approach to investment planning. The company's investment plans and rate filing to the OEB will reflect its desire to address the needs and preferences of customers, to make prudent and cost effective decisions, to proactively address emerging risks, and to be innovative.

Participants were then taken through the customer engagement process which is consistent with the OEB's Renewed Regulatory Framework.

Customers were told that the Investment Plan will be informed by customer needs and preferences, analysis of asset needs, and the organization's ability to resource, schedule and execute work.

Participants were reminded that all transmission-connected customers will have the opportunity to provide input that will support the development of the Investment Plan through the various mechanisms outlined in Part A: one-on-one discussions, larger professionally facilitated customer engagement sessions, as well as the self-directed online consultation tool.

WE TAKE A RISK-BASED APPROACH TO INVESTMENT

We are accountable to plan, operate, build, and maintain an affordable, robust, and flexible transmission system that **serves Ontario's needs** and meets our obligations as part of the North American grid.

Our investment plan will identify, prioritize, and schedule the investments we make in our system. On this basis, we aim to create value by:

- Ensuring our investment plan considers and reflects the needs and preferences of our customers by achieving a balance between managing reliability risk, service and cost.
- Recognizing every dollar we spend comes at a cost to our customers and the people of Ontario.
- Making prudent, cost-effective, short and long-term investments in our transmission system so that the electricity needs of Ontario are met now and into the future.
- Addressing emerging risks of our system, and always looking for ways to economically extend the life of existing transmission assets.
- Being innovative by adapting new/proven technologies, equipment, and processes that contribute to the efficiency of our operation.

OUR CUSTOMER ENGAGEMENT PROCESS

Hydro One is in the process of **developing its Transmission Investment Plan** for 2017 and beyond.

This investment plan will in turn, underpin our **Transmission Rate Application** to the OEB later this spring.

Our Investment Plan will be based on our customers' needs and preferences, our analysis of **assets' needs** and of our **ability to resource, schedule and execute work.**

All transmission-connected customers will have the opportunity to provide input that will support the development of the Investment Plan through:

- One-on-one discussions
- Larger, professionally facilitated customer engagement sessions held in Toronto, London, Ottawa, Thunder Bay, and Sudbury
- An online survey

The approach we are taking is consistent with the OEB's Renewed Regulatory Framework.

SUMMARY OF SYSTEM PERFORMANCE

Hydro One's transmission reliability has remained flat.

The **transmission system faces increasing challenges** due to asset condition.

Equipment performance is the largest controllable factor, contributing 42% of system *interruption*[1] minutes. Assets continue to age (e.g., 20% of conductors now beyond *expected service life*[2] of 70 years).

Evidence suggests that underlying reliability risk is increasing:

- Equipment outages[3] caused by failure or necessary repairs/replacements increased ~300% from 2011 – 2015
- Increased duration of placing customers, normally served by a multi-circuit system[4] on single supply, increasing interruption risk by ~400%

Condition assessments have identified critical replacement needs, for example:

- 2,300 cct-km of conductors identified for priority replacement due to being at or near end of useful life[5]
- 9,100 steel towers at heightened failure risk due to depletion of their corrosion protection layer

Hydro One continues to take action to mitigate reliability risk by:

- Managing equipment performance through robust, condition-based asset replacement programs
- Reducing customer exposure to single-supply through improved planning and work processes

1. Outages on the transmission system that interrupt the supply of energy to transmission customers.
2. The average time in years that an asset can be expected to operate under normal system conditions.
3. The removal of facilities from service, unavailability for connection of facilities, temporary de-rating, restriction of use or reduction in the performance of facilities for any reason, including to permit the inspection, testing, maintenance or repair of facilities.
4. Delivery points served by multiple transmission circuits, creating system redundancy; tend to be located in the southern areas of the province.
5. As asset-specific determination based on an asset's condition, criticality, performance, demographics, utilization and economics.

CUSTOMER NEEDS AND PREFERENCES

Q: As a transmission customer, what's most important to you to ensure your needs and preferences are met?

FREQUENCY VS. DURATION OF SERVICE INTERRUPTIONS

LDCs indicated that duration of interruptions is a greater concern than frequency of interruptions, while for large industrial businesses frequency of interruptions is a greater concern. However, most customers agreed that improvements in both are among their top needs. Planned outages are considered by many to be much more manageable and less of a concern than unplanned interruptions.

> "We are seeing prolonged periods of time where we're on a single-line supply. One line is out of service, it's taken apart, not available on recall and then we're totally black for 70% of our customers. It's happened repeatedly in the last five years. Our sense is those assets aren't being regularly inspected…"
>
> "It's the unplanned outages. That's what kills us…we're down for 16 to 24 hours. You measure it being out for a second and I'm out for a day. We can deal with the planned. The unplanned stuff, depending on how and where it hits, we can be out for a day."
>
> "In our world, sometimes we're losing a day even in Southwestern Ontario. A day is a day. We're making [quantity deleted for customer confidentiality] a day. Takes an hour to figure out what's wrong. Then you send people home and you're not sure when you call them back….very expensive proposition. Recently we…lost 24 hours. It's expensive."

TRANSMISSION RATES/COSTS

While not the most frequently mentioned need, cost was raised at various times at most sessions. The desire for good reliability at a competitive or low cost is universal. For LDCs, since the transmission rate is a pass-through cost, the issue is primarily the impact on the ratepayer and some expressed concern that ratepayers are feeling rate fatigue. The inability to effectively explain reasons for transmission rate increases to their customers is a shared challenge across many LDCs.

One LDC in particular indicated some ratepayers would not be willing to pay for improved reliability. A few large industrial customers discussed the fact that their businesses are tied to a commodity price and when the price is low, securing investment for their own asset management or replacing assets can be a challenge. Thus there is an even greater need to understand Hydro One's asset management planning in order to understand if the plan justifies an increase in rates.

"Needs… Quality product delivered reliably at a competitive price, the same that I expect of all vendors supporting a 24/7 operation."

"Good reliability at reasonable rates."

"Supply reliability at a reasonable competitive rate."

SYSTEM RELIABILITY

Reliability was the most frequently and consistently mentioned need raised by customers across all consultation activities. In fact, there was a great deal of consensus across the customers who participated regardless of their role as an LDC, generator or large industrial business. Outages and interruptions are of great concern and many customers provided examples of the financial and health and safety impacts of even short interruptions in service.

"Every time there is an unplanned outage, even if we are back online in 15-20 minutes it's a 2 hour interruption which is a $100,000 cost."

"Another transformer failure puts us out of business for a very long time."

"It takes 8 hours to get our facility back online. Health and safety issues [arise] in a blackout. There was a fire caused in one instance. It puts employees at a lot of risk."

"Unreliable service, especially when we have no warning of the loss of power or power quality, costs us the most."

COMMUNICATION

The need for greater communication between Hydro One and transmission-connected customers was articulated often through the consultation activities. Some customers stated that historically long term plans were not communicated to them so they have struggled with certain aspects of their own localized or distribution network planning as a result. Most were appreciative of the opportunity to hear about, and more importantly to have input into, Hydro One's system performance, maintenance activities and direction for its five year planning.

"Ensure transparency and good reporting. You do a pretty good job of that so far. It could even be expanded. We would like to see metrics on those parameters [reliability and power quality]that are critical to us and to our customers, and have transparency so we can see deeper than we do today so we understand the issues."

"[We need] timely communication and cooperation/coordination from Hydro One to ensure a balance between system risk and asset maintenance."

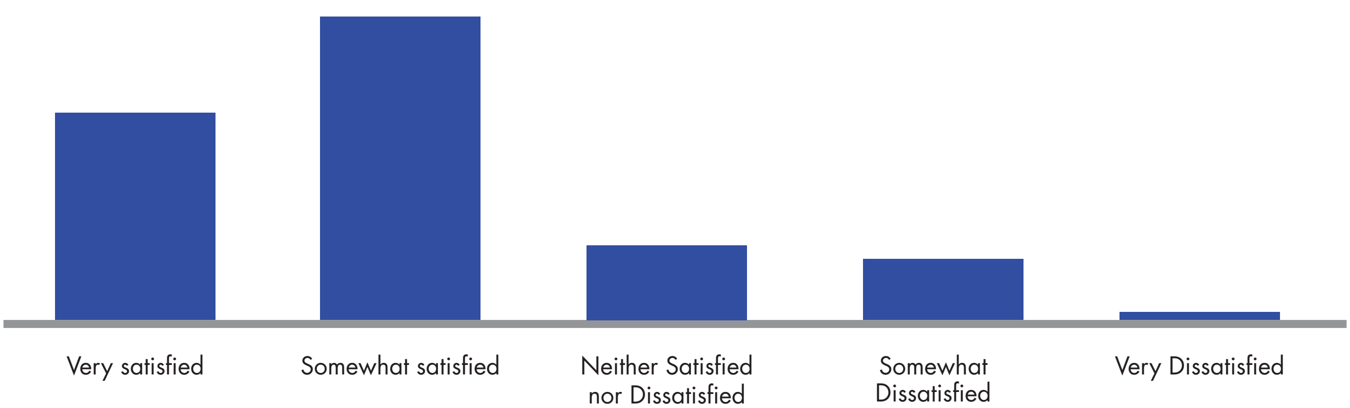
"[We would like a] a report on power quality every quarter or 6 month[s]…we would like to be in touch with an account manager at least once a year….we would like to know short and long term plans of Hydro One and planned power outages months in advance if possible."

OVERALL SATISFACTION WITH HYDRO ONE PERFORMANCE

Q: As a transmission customer, what's most important to you to ensure your needs and preferences are met?

Customers expressed satisfaction with Hydro One's performance overall with many customers offering a rating of 4 or 5 on a 5 points scale of satisfaction (a rating of 5 represents 'very satisfied'). Some customers were clear to point out that they are more satisfied with some aspects of Hydro One than others. Reliability of service and power quality are two aspects that customers are less satisfied with. There is a general sentiment that customers have a good relationship with their Account Executive, in fact, some customers organically offered examples of how their Account Executive has been helpful and effective in their role with the customer. However, concerns were prevalent that the broader Hydro One relationship should be more transparent, and that management should be more open in sharing information that affects its decision-making particularly where the customer and Hydro One are dealing with similar issues.

SATISFACTION WITH HYDRO ONE'S PERFORMANCE



As a transmission customer, overall, how satisfied are you with Hydro One's performance?
Base: Wave 2 and Wave 3 participants who responded to the question (n=51)

CUSTOMER CHALLENGES

Q. Thinking about your electricity needs as a transmission customer, what are the main challenges you face in your organization and industry today?)

Unplanned interruptions were frequently listed as one of the main challenges that customers face today. The financial implications on the business or organization can be in the millions of dollars for a short unplanned interruption. Some focused on specific capacity issues and development projects that impact their supply and/or business as key challenges they face.

"Supply point reliability -- Between 2010 and 2014 nearly 40% of our total customer outage minutes were due to Hydro One loss of supply."

"Not going broke - Ontario is a very uncompetitive environment in which to operate a business, and the mix of high electricity costs coupled with decreasing (power) quality and deceasing delivery (unexpected outages) is a big part of the competitive nature of Ontario."

Customers expressed that Hydro One does a good job of coordinating and scheduling planned outages with businesses and LDCs, but they continue to see this as a challenge for them, particularly if the number of planned outages increases. Some customers indicated that getting internal buy-in for halting or re-structuring production can be a challenge.

Speaking on behalf of their end customers, several LDC representatives re-iterated at this point that there is some amount of rate increase fatigue among their customers. LDCs are mindful of the need to invest in sustainment programs and asset management, but struggle with how to explain this to the ratepayer. They acknowledge that ratepayers do not have a good understanding of the transmission portion of their bill. Several LDCs feel the stress of having to address rate increases with ratepayers.

"... [the challenge is] replacing aging assets without escalating costs to our customers."

"[the challenge is] maintaining reliability, while controlling costs. Transmission costs are something an LDC cannot control and they are passed through. Reliability of a transmission system is viewed by customers the same as distribution reliability. An outage affects a customer the same regardless of TX or DX."

Consistent with comments related to customer needs and preferences there was a sentiment held by some customers that they are "in the dark" about Hydro One's long-term asset planning and sustainment goals. In fact, many commented that the consultation session they participated in was highly valued, and they appreciated the opportunity to hear Hydro One's plans in detail, so that they can determine on their own if they feel that the rate increase required to deliver the plan strikes the right balance.

"[the challenge is] lack of transparency regarding operational load flow model so that we can conduct analysis in house."

A couple of customers expressed some confusion about why the transmission rates and distribution rates are different and stated that this was a challenge for them.

Customers across large industrial businesses, LDCs and generators spoke of being frustrated that transmission-related activities or work in their immediate vicinity or vital to their organization is not being addressed quickly enough. At least one customer indicated that their ongoing issues with capacity are a major challenge to the sustainment and growth of their business. Naturally, customers were keenly interested in how assets in their specific area are being addressed. This comment was not always tied to sustainment of assets, as some customers referenced development projects.

CUSTOMER CONCERNS

Q. Please rank for us in order how concerned your organization is (or would be) about the following regarding Hydro One.

- Hydro One's business relationship with you
- An increase in transmission rates less than 5%
- An increase in transmission rates more than 5%
- Adequate asset maintenance and replacement
- The number of unplanned interruptions
- The number of planned or scheduled outages
- Power quality
- Getting assurance that an increase in rates will improve reliability
- Hydro One asks for my organization's input while developing their investment plan
- The input I provide is reflected in Hydro One's investment plan

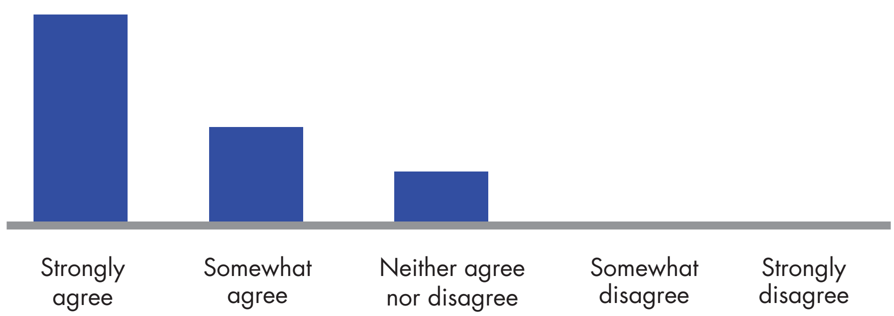
Interruptions and rates were the primary concerns, with adequate asset management and replacement being a secondary concern. Other concerns were acknowledged as being important but interruptions have the biggest impacts on productivity and revenue loss, with rates being a concern for managing bottom lines and communicating with ratepayers.

ADDRESSING RELIABILITY RISKS VS. DEFERRING INVESTMENT

Q. To what extent do you agree that Hydro One needs to be more proactive in addressing current and emerging reliability risks now, rather than deferring investments?

For the most part, customers believed that Hydro One does need to be more proactive in addressing current and emerging reliability risk now. Those that didn't strongly agree with this statement stated that they themselves have not had many transmission outages. While there was general acceptance that Hydro One's assets appear to be aged, they indicated that they did not have enough information on asset age and performance to answer the question with confidence.

ADDRESSING RELIABILITY RISKS VS. DEFERRING INVESTMENT



To what extent do you agree that Hydro One needs to be more proactive in addressing current and emerging reliability risks now, rather than deferring investments.
Base: Wave 2 and Wave 3 participants who responded to the question (n=45)

"We have not had many transmission outages in our area. The assets appear aged. There has not been enough information on asset age and performance to answer this question with confidence."

"Hydro One is the third largest electricity cost in North America. If you improve reliability then you should be able to reduce cost."

"We have assets to replace…if your investment is based on the assets we need tons of lead time, by the time you start it your risk is already a reality. The more proactive you can be the better."

"You've got to jump in somewhere I guess. We ranked it pretty high, a 4 [somewhat agree]."

SYSTEM PERFORMANCE

At this point in the consultation sessions customers were led through a presentation by a representative of Hydro One or advised to read through the presentation if participating via online only. The presentation detailed Hydro One's system performance for the past five years.

During and immediately following this portion of the presentation, customers asked clarifying questions or expressed any concerns about the information being presented. A common question was whether or not momentary outages count as an outage for the purposes of measuring the change in the number of unplanned outages that occurred – this question was answered in the affirmative. Customers agreed that momentary outages should count as those are just as impactful to some organizations as longer interruptions.

Several customers inquired as to whether Hydro One has historical data going back more than the five years shown in the presentation on the number of unplanned outage hours due to equipment failure. They would like the opportunity to review the trend in unplanned outage hours due to equipment failure in the context of historical capital expenditure on sustainment. There was also interest in understanding what benchmarking Hydro One has done. There was some negative criticism that Hydro One has not been spending sufficiently on sustainment capital historically.

Another common question was how asset condition assessments are made – who determines them and are the metrics used the right ones, for example for conductor sample testing. At least one customer questioned whether condition assessment is the best/regulator-preferred methodology.

Clarifying why transformer work is so complicated and crucial was needed for some, but obvious to others. A couple of LDCs suggested that they may need to have a transformer in the background to mitigate risk, and offered that with better coordination, LDCs can mitigate risk by taking a transformer out of service with lesser impact.

At this stage there was concern about the number of unplanned outage hours due to equipment failure being very high. Some customers inquired about Hydro One's maintenance spending and spoke negatively about past diligence shown in investment in maintenance generally and on specific elements and equipment. A few inquired about how Hydro One undertakes steel tower coating and associated timing.

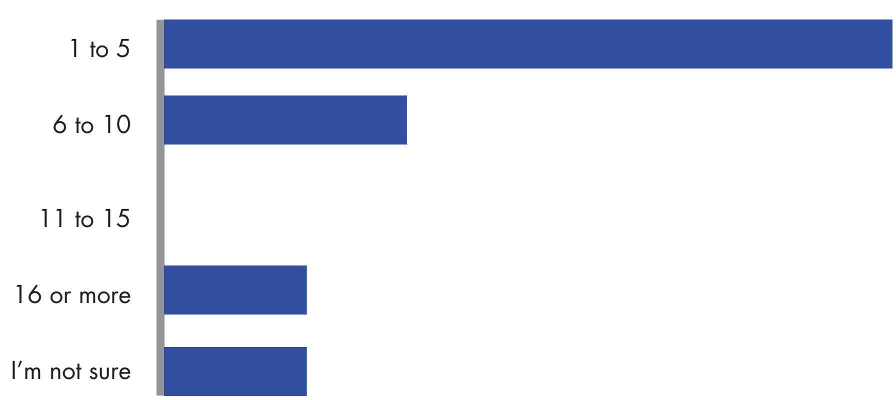
EXPERIENCE WITH UNPLANNED INTERRUPTIONS

Q. Are you aware of how many unplanned interruptions your organization experienced in 2015? Please tell us the number of interruptions.

When asked to indicate the number of unplanned interruptions their organization experienced in 2015, opinions varied quite a bit. The opinions of customers varied primarily regionally, but to some extent by LDC versus industrial as well.

Those on a single-circuit supply in the North are more likely to experience interruptions than those on the multi-circuit supply in the South. During discussions, customers stated the consequences of unplanned interruptions. For example, for one mine a one-day outage can cost tens of millions in lost productivity. For one paper mill, a ten-second interruption takes 8-10 hours to come back online, and costs run between $500,000 to $1 million.

NUMBER OF UNPLANNED INTERRUPTIONS EXPERIENCED IN 2015



Are you aware of how many unplanned interruptions your organization experienced in 2015?
Base: Wave 2 and Wave 3 participants who responded to the question (n=41)

RELIABILITY PERFORMANCE VS. RELIABILITY RISK

Q. Do you have a good understanding of the difference between the two?

The following definitions were provided to customers.

Reliability performance is a measure of the ability of the transmission system to supply customers' electric power and energy requirements. It is calculated based upon the duration and frequency of interruptions at prescribed delivery points.

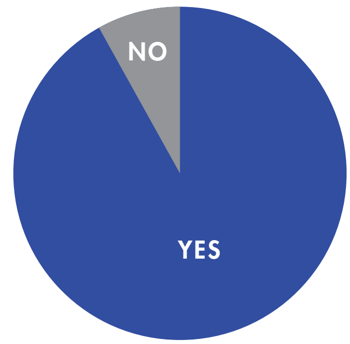
Reliability risk is a relative measure of the possibility that the transmission system will not supply customers' electric power and energy requirements, at all times, due to planned and unplanned outages of system components.

Most customers indicated that they understood the difference between reliability performance and reliability risk. Generally customers understood performance to be looking back and risk to be forward looking. A few customers said that performance and risk are intrinsically linked.

"We're involved in our asset integrity, a lot is very similar. It is kind of nice to hear we are not doing this in isolation."

"Once reliability starts to fall it's too late."

UNDERSTANDING RELIABILITY PERFORMANCE VS. RISK



Do you feel you have a good understanding of the difference between reliability performance and reliability risk?
Base: Wave 2 and Wave 3 participants who responded to the question (n=39)

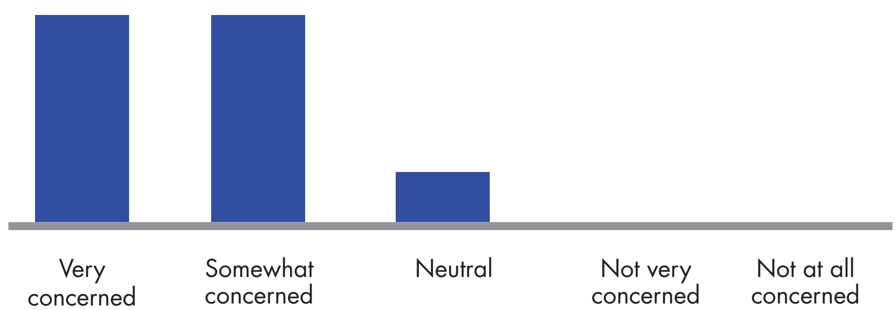
CONCERN ABOUT RELIABILITY RISK

Q. And, how concerned are you about system reliability risk?

Most customers indicated being concerned about system reliability risk. They acknowledge the assets are aging and this will impact performance eventually. Unplanned outages are of significantly greater concern than planned outages, the latter of which several customers said could be managed.

A few customers expressed a dissenting view and indicated that system reliability risk was not their concern.

CONCERN ABOUT RELIABILITY RISK



How concerned are you about system reliability risk?
Base: Wave 2 and Wave 3 participants who responded to the question (n=40)

"You're asking about risk not performance. For me, as an end user, risk is your problem. My problem is performance. At the end of the day, do I have it or not? I'm worried about how many outage hours I have not how many I potentially have."

ILLUSTRATIVE RELIABILITY RISK VS. RATE SCENARIOS

Customers in all sessions were taken through three illustrative investment scenarios in detail. The scenarios were illustrative examples of investment plans detailing key elements, investments by asset class, and overall risk profile.

Customers were shown each scenario in detail, including the four major asset replacement programs, and were then shown a summary of all three scenarios side-by-side, which also included the corresponding increase on transmission rates.

Customers were advised that they were not being asked to choose a preferred scenario, rather to provide feedback on each scenario as it relates to magnitude and scope, pacing, timing, and rate increases, so that Hydro One could understand the strengths and weaknesses of each scenario from the perspective of customers.

Hydro One representatives clarified that the scenarios related only to sustainment capital expenditures, and that they did not include development work (a separate line item) or operating and common costs (also separate line items). The forecast rate impacts did not consider changes in load or OM&A costs.

Further, they clarified that the investments shown are system-wide, meaning they take into account all of the work needed to be done within the province of Ontario and determined courses of action that would address investments at a system level. Therefore, the investments are intended to improve system reliability risk as an aggregate, and thus individual customers may not see investments in their immediate vicinity or on equipment vital to their organization. Similarly, changes in reliability risk across the system may or may not impact their individual service experience (may not mean a decline in the number of unplanned interruptions that they experience).

Additionally, Hydro One discussed the idea of investing now in order to mitigate risk in the future and made it clear that these sustainment capital expenditures were ultimately non-discretionary investments, as they would have to occur eventually, as many assets and assets classes are reaching end-of-life.

Customers were advised that Scenario 1 would result in an increased reliability risk of approximately 10%, Scenario 2 would mean risk would remain essentially flat, and Scenario 3 would result in a decrease in reliability risk by approximately 10%. In terms of investment, for each $500 million in incremental capital investment approximately 10% improvement in reliability risk is expected.

INVESTMENT SCENARIOS

hydro one

Illustrative scenarios have been developed for various levels of sustainment expenditures.

These in turn, **result in different rate impacts and reliability risks.**

These scenarios focus on the Sustainment Capital portion of our Investment Plan and are meant to represent a spectrum of potential investments.

We do not have a recommended scenario, nor are we asking you to choose" from the scenarios presented.

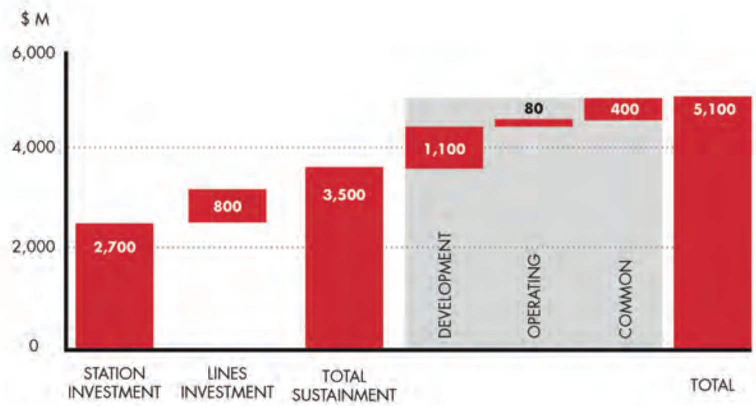
The asset solutions identified are flexible. The inclusion and pacing of investments in the plan may vary from what is presented in the scenarios. Through this conversation, we would like to better understand your business needs and preferences to inform our 5-year Investment Plan.

SCENARIO ONE

SCENARIO 1
~$5,100M (2016 – 2020)

KEY ELEMENTS OF SCENARIO 1

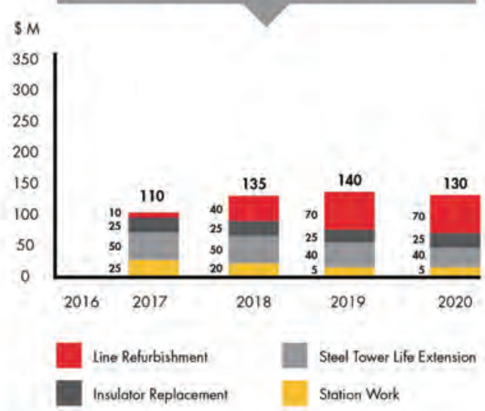
- Coordinated replacement of multiple elements at stations to reduce outages
- Investment to replace high risk air-blast circuit breakers
- Replacement of aging transformer population
- Does not fully address increasing risk due to line asset aging/conditions



Overall risk profile:
Reliability risk expected to increase

SCENARIOS TWO AND THREE

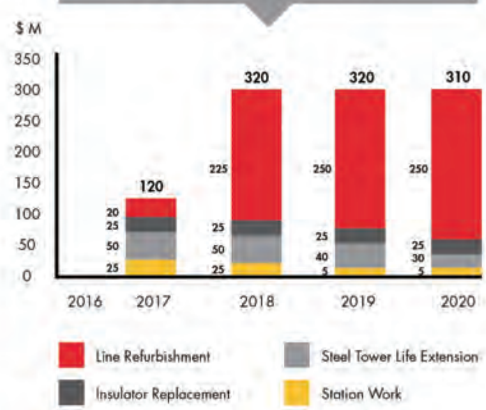
SCENARIO 2
~$520M in incremental CapEx from 2016 – 2020



- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 1,200 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Current reliability risk expected to remain unchanged

SCENARIO 3
~$1.1B in incremental CapEx from 2016 – 2020



- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 2,300 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Reliability risk expected to decrease

Hydro One also addressed a "Zero Scenario" in which the rate increase would be capped at historic levels (approximately 3.2%) as customers indicated it would be helpful to illustrate what that might look like.

> "Might be useful to show what the decrease in reliability might be if nothing was done. 'If we do nothing and don't raise your rates, this is what you'll get'…Show us the nosedive and what it takes to come out of that dive…"

Hydro One calculated the reliability risk level for this Scenario and determined that it would result in an unacceptable reliability risk increase (approximately 20% increased reliability risk), and therefore could not consider it.

MAGNITUDE AND SCOPE OF INVESTMENT

The scope of investment in Scenario 1 was perceived as an appropriate minimum to some customers given the information they had heard about system performance and in particular the number of unplanned outages and interruptions that have been caused by equipment failure. However, there were concerns raised about the increased reliability risk in this scenario and most customers indicated being unwilling to accept a rate increase for a transmission system plan where reliability risk still increases. For many this was not even worthy of discussion. Increased risk, particularly the magnitude of the increase in risk (approximately 10%) is unacceptable. A few customers commented that Scenario 1 should include information on the future rate impact of deferring investment.

Based on the written and oral feedback, Scenario 2 seemed like a balanced approach that was perceived as being more acceptable as it related to the reliability risk not increasing, but remaining static. Large industrial customers, particularly those in the North, were the most likely to feel that unchanged risk is unacceptable. The critical issue is that they want to see an improvement in the reliability and quality of their service. For their specific situations, the question was whether the expected rate increase in cost is commensurate with the level of savings they will realize from reduced interruptions, or what their future expected costs will be if reliability worsens.

Some customers expressed the opinion that Scenario 3 was the most responsible course of action, particularly as it related to addressing service interruptions. A few customers shared that the difference [in rate impacts] between Scenario 1 and Three was not significant and it is worth the cost when compared against lowering reliability risk by 10%. However, a few indicated that the proposed 6.8% rate increase in Scenario 3 was unaffordable.

Feedback on the specific asset class investments other than line work (insulators, steels towers, and station work) was limited. Some concerns were raised about the reliability and potential failure of new equipment, and the availability of backup assets in case of failure. However, customers mostly commented on the line work since that was the item with the biggest change in scope from scenario to scenario.

INVESTMENT PACING

The spike in line investments from Scenario 2 to Scenario 3 seemed sudden to a few who wondered if a more level approach would be more reasonable. The spike in investments between these two scenarios also raised questions about Hydro One's ability to ramp up internally as well as engage third party workers for the amount of work needed. There was some skepticism that the elements of Scenario 3 could be accomplished within five years.

> "The difference between Scenario 1 and 3 is significant. Not saying Scenario 3 isn't right, but how quickly [can]you get there. Pacing or smoothing that more so than what you've illustrated, may be a more appropriate approach. [The] question is time frame."

RATE INCREASES

A couple of key clarifications were required when discussing rate increases. The first was that the rate increases shown would be compounded over five years, and the second was that the increases shown would apply only to transmission rates and not the overall bill. While Hydro One stated that for the average customer the transmission rate represents 10% of the bill, one customer estimated it to be closer to 25% of their bill.

A few customers pushed back on why rate increases need to jump to a 5.1% minimum from the historical 3.2%.

> "I'm having a hard time understanding the starting point in Scenario 1. Your rate increase has been on par with inflation. Why is the starting point rate increase so high? Must be something we're not seeing that does not relate to capital. If starting point wasn't so high, it would be much easier to say yes to Scenario 3."

> "All in electricity rates (supply, delivery, global adjustment, etc...) are already too high for consumers and industry alike. The amount of unplanned outages has not been that significant in recent years to warrant excessive capital spending to mitigate risk. Effort should be made to keep rates at current levels."

IMPACT ON RATEPAYERS

LDCs expressed concern about the impact on ratepayers and the level of acceptance of an increase among their customers given that the transmission rate increase would be a pass-through cost to ratepayers. Ratepayers don't understand the distinction between transmission and distribution rates, and only know that their bills are increasing. The LDC is the one held accountable for these increases, and one customer mentioned that there is rate increase fatigue and sensitivity among ratepayers in their region.

> "A big part will be [to be] armed with info to share with our customers, holder of the bill. They will want to see the bigger picture."

INDIVIDUAL BENEFIT VS. SYSTEM BENEFIT

Adding to the concern about the impact on ratepayers, LDCs indicated that they do not have any information as to what direct benefit their region would receive in terms of improved reliability risk or performance as a result of the increase in the transmission rate. LDCs held this concern while acknowledging that deferring investments to address risk now will only create more issues that could create a need for even greater investments and rate increases in the future.

Large industrial customers more directly expressed a preference for investments on aspects of the system that will benefit their immediate vicinity and thus their organization.

> "The reliability for us is on the transmission system, we would love to see improvement but this is province wide."
>
> "I am here because I [would like] to be aware of the investments made locally to me. I want to know the priority areas."

A few customers indicated that the illustrative scenarios did not provide enough information about how the investments would be allocated or sufficient evidence that a rate increase is necessary. Clarifying questions were also raised about how the rate increases were calculated.

> "We do not accept the premise that a rate increase will address reliability risk, or indeed that a rate increase is justified at all."
>
> "It tells me nothing except that Hydro One plans to spend $5.1 billion dollars and it will have no direct benefit…It does not explain where the money is spent, how projects are prioritized, what the business case is, and the long term impact on O&M expense."

OTHER POINTS OF DISCUSSION

There were other themes that emerged organically from the discussions on the illustrative scenarios.

FINANCIAL

Benchmarking: A few customers across Wave One and Two inquired about how Hydro One's capital expenditure associated with each scenario compares against other transmission utilities. In these cases, customers were not looking for benchmarking of historical expenditure but rather for comparative information relating to future capital investment plans of comparator utilities.

"How does Scenario 2 and 3 compare with those peer utilities and their investment levels?"

The importance of competitively priced energy: A few customers expressed their belief that increasing rates, in particular without the assurance of improved reliability performance, will contribute to businesses being driven out of Ontario. However, one LDC customer stated that Hydro One is not responsible for ensuring competitiveness in Ontario.

"…effort should be made to keep rates at current levels…to avoid driving further investment and industry from the province."

"Skyrocketing hydro costs as well as increased transmission costs and additional charges are making it very difficult to compete in a competitive business environment. We have shifted our operations to off peak periods to reduce electricity costs and Hydro One is charging Network Service Charges for peaks that occur in the off-peak, shoulder period."

Padding: One customer expressed concern that Hydro One needs to increase its asset portfolio in order to get a bigger rate increase from the regulator.

"This really looks like pocket padding to get more revenue for your shareholders due to a larger, overpriced asset base – I do not see where you have an incentive to save – the bigger your asset portfolio, the more money you can ask for at the OEB."

Raising Capital or Other Revenue Sources: Customers wanted to know if transmission rates are Hydro One's only source of income. One customer also asked if Hydro One is able to raise capital to finance the investment plan rather than increase transmission rates.

"*To what extent can they tap the public markets for money now that they're a public company...do a share offering to raise capital to finance that. Would that be something that could be considered, so you get a pool of money to finance sustainment activity as opposed to ratepayers of the province."*

Re-allocation: Customers asked whether Hydro One could re-allocate the funds dedicated to sustainment within Scenario 1 to decrease reliability risk. Questions also arose around whether Hydro One should defer funds currently dedicated to development within Scenario 1 to sustainment in order to mitigate rate increases.

"Is there a way…with a 5.1 billion dollar Scenario 1, to rearrange the work program to have a better risk profile? That is – if Scenario 1 reflects your spending over the last 5 years and relations between stations, lines, towers, is there a rebalancing within the 5.1 that gives you a better reliability outcome?"

"The development money…what is this money? We are paying as a ratepayer for reliability and paying for development money that has no impact for us. The scenarios I am okay with reliability but foregoing it against development is not good. If you don't have the money you keep the heart going."

Level of investments relative to asset value: Customers pointed out that $5B represents half the value of Hydro One's transmission assets (asset value as outlined in the presentation by Hydro One). This was perceived as a significant investment that should span a longer period, and caused customers to question Hydro One's ability to secure sufficient resources to execute the intended work.

"Adding $5.1B in CapEx over 5 years is a significant cost/investment that should be amortized over the next 40 to 70 year life of the assets."

OPERATIONS

Cooperation: Planned outages should ideally be bundled and scheduled in the most economical and least intrusive way. Currently for some customers, cooperation with Hydro One is working well. While others feel they are not provided sufficient information about asset work being done in their regions, or directly related to their organizations. Customers expressed willingness to work with Hydro One in order to mitigate their own vulnerability as it related to potential outages and interruptions.

Improving maintenance efficiencies: Customers would like to know what if any efficiencies are being considered rather than simply raising rates. For example, would it be possible to increase efficiency in maintenance plans in an economically beneficial way.

"Hydro One is using reliability risk as a lever to increase rates, when it should be seeking to be more effective in how it manages costs."

"Given how Hydro One is stating they really need this level of investment to make up for prior years shortfalls, then the expectation is that extra efforts will be made elsewhere such as OM&A to reduce the rate impact to inflation."

New asset maintenance work efficiencies: There was a suggestion that by replacing old assets with new ones, that Hydro One would see a compounding benefit on maintenance costs. This in turn would mitigate future rate increases. The customer wanted to know if that presumption was true and what the financial benefits would look like.

"If you replace the asset, it's very probabl[e] you won't have to maintain at the same level of the old asset. So there is a case to be made that as you spend more replacing the asset, you suspect the OM&A element should [decline]. And it would be very helpful to see the benefit of that to demonstrate that increased expenditures on those assets has a compounding benefit. It's also to unlock those unnecessary maintenance practices that don't need to be there. It's more economic[al] just to replace it."

Human resources: Several customers questioned Hydro One's ability to secure sufficient resources to support the investments Scenarios 2 and 3. They specifically questioned if Hydro One has the internal capacity to support the investments, or if is there a need to bring in third party workers. This was a concern particularly as it related to the increased line work outlined in Scenario 3.

"If your plan's gonna require two to three times the resources of your previous peak, how realistic is that? …There are other large LDCs trying to secure third-party resources at an aggressive rate at the same time. So the availability and cost in the market may be a surprise to all of us."

PLANNING

Coordination: There was a desire for greater coordination with Hydro One and transmission-connected customers when work is being done. This comment was made in the context of a thinking about the design of the investment plan.

"In the design of the investment, can you consider [from a] coordination point of view? Whenever he [person at organization] asks why Hydro One takes this out. Then he gets the answer [from Hydro One] it's going to potentially impact the system. It may be a change in work practice but we see a lot more of this."

Disaster planning: Since catastrophic unplanned service interruptions can be weather-related, a customer questioned if it makes sense to make investments that cannot prevent this from occurring.

"If it comes down to what we want to pay for insurance, this investment will not stop a catastrophic event from occurring (ice storm, forest fire, etc.) so is $5B worth reduced interruptions?"

Mandated work interfering with capital plan: One LDC mentioned that they have an investment plan but are then mandated by their municipality to do other work, and therefore they get sidetracked. It raised the question as to whether Hydro One has the same challenges.

"We have a particular bucket of money; city tells you to move poles, a million dollars' worth of capital work you have to do…"

Order of how the assets would be repaired/replaced: Customers wanted to know if priority was being given to crucial assets – such as those that provide power to nuclear stations; those areas that are currently on a single-line supply/radial circuit; and large industrial businesses for whom service interruptions have serious financial consequences.

"Is it possible to flag some assets as being crucial and 'cannot fail', and therefore be placed in priority sequence."

"I know we couldn't live with a 9% increase in risk of unreliability at [a nuclear station]."

"We've tried to impress upon Hydro One…thinking of [the] industrial cluster second to nuclear impact economically."

Time period: To some customers five years feels like a short period to be considering investment plans. These customers questioned if Hydro One should be planning beyond 2021.

"A longer time duration shows a lot, and skews the data. You usually need at least 7 years of data, this set appears short."

Planned outages vs. unplanned interruptions: Some customers indicated that unplanned interruptions have more negative consequences than planned outages and these interruptions are the primary concern. They would like to know if it is possible to focus on and improve reliability risk on unplanned interruptions only.

Appropriate measures of success: A few customers wanted more clarity on what Hydro One sees as the goal when it comes to reliability. What level of reliability risk or performance is it striving for.

"…what could be of more value would be something to show where you've been, what you're asking for and where it will take you. This doesn't speak to what you'll achieve from this investment."

INCREASING CONCERNS ABOUT RELIABILITY AMONG RATEPAYERS

A few of the LDCs indicated that feedback from their end customers suggests that ratepayers' expectations and scrutiny around reliability is increasing.

"As an LDC we have public hearings with the consumers. One survey question we had was regarding their expectations. 25% of our customers expect zero outages."

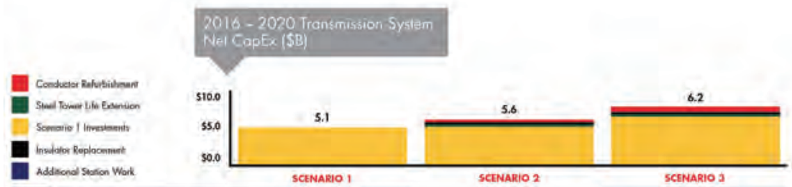
SUMMARY OF SCENARIO FEEDBACK

Although customers were not asked to choose one scenario and told that the scenarios were to be considered illustrative and flexible, some customers did state a preference.

Most of those who offered an opinion stated that their preference landed between Scenarios 2 and 3. They stated that an investment level between Scenarios 2 and 3 was most appropriate.

However, they emphasized that they must see an improvement in reliability and quality. In practical terms, they are looking for fewer unplanned interruptions, and investments that benefit their organizations or regions directly.

OVERVIEW OF THREE POTENTIAL SCENARIOS



		SCENARIO 1	SCENARIO 2	SCENARIO 3
Capital Spend	Sustainment ($B)	3.5	4.0	4.6
	Development ($B)	1.1	1.1	1.1
	Other ($B)	0.5	0.5	0.5
Expected Outcomes	Frequency and duration of interruptions	▲ Expected increase in line-related interruptions	▶ Some increase in lines risk offset by limiting unplanned outages and improved station performance	▼ Reduce risk from lines and continue to limit exposure to unplanned outages
	Reliability risk[1]	▲ Risk is expected to increase	▶ Current risk expected to remain essentially unchanged	▼ Risk is expected to decrease
Rates	Transmission rate impact (Compound Annual Growth Rate for 2017 – 2020)[2]	▲ ~5.8%	▲ ~6.3%	▲ ~6.8%

1. Reliability risk is a probabilistic calculation based on asset demographics and the historical relationship between its age and its failure or replacement.
2. Excludes impacts of potential changes in load forecast and any potential change to operations and maintenance spending.

Participants were given an opportunity to create their ideal aggregate scenario and encouraged to do so. While a few customers particularly those who completed the online consultation tool, offered comments, most did not. From Wave Two, it was apparent that some participants were reasonably satisfied with one or more of the scenarios. Others didn't offer comment because they didn't feel they had the right information or sufficient information in order to offer a suggestion.

The main comments and questions that arose orally and in writing about each of the illustrative investment scenarios have been summarized in the chart on below.

Scenario One

- Perceived as the bare minimum targeting the highest risk assets and largest outages.
- Seen by many as insufficient to address reliability risk concerns.
- While many expressed concern that an increase in reliability risk is unacceptable, they were also sensitive to the proposed rate increase.
- Customers questioned if there would be efficiencies in other areas- for example, in OM&A- that could help offset the rate increase.
- Customers asked if it possible to re-allocate the work such that it decreases reliability risk, without raising the rate.

Scenario Two

- Perceived to be a comfortable and conservative middle ground, and most balanced approach.
- At minimum, some would like to see reliability remain unchanged (as opposed to increasing risk of Scenario 1) and this Scenario would address that.
- The investment required to have reliability remain unchanged is perceived as disproportionate to some.
- The pace increase from Scenario 1 is thought to be more comfortable and realistic than Scenario 3.

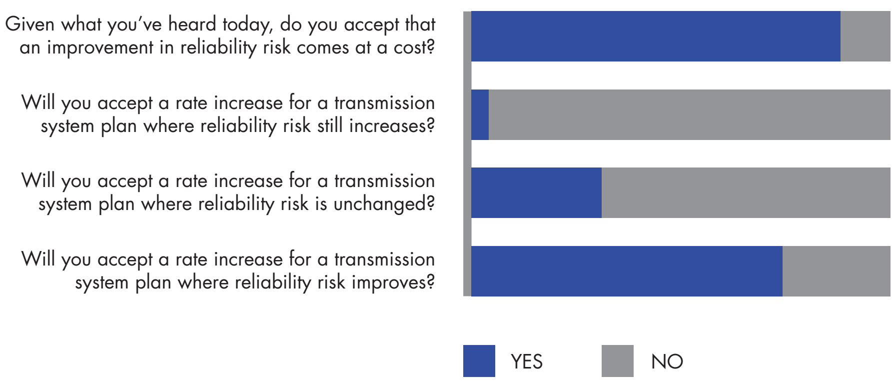
Scenario Three

- The spike from Scenario 2 and 3 seemed high to some, who thought that the pacing and approach should be more level.
- Questions arose about resource capacity - would Hydro One be able to ramp up internally as needed in order to complete this work. As well, customer asked if Hydro One would have to hire third party workers, and asked what would happen if they are unavailable.
- A few large industrial customer felt strongly that Scenario 3 was the minimum in terms of asset maintenance and replacement and capital investment. These businesses are the ones who struggle most with interruptions.
- The rate impact was perceived as being too high and unaffordable to some.

RELIABILITY RISK VS. RATES

Customers were posed reliability risk vs. rates trade-off questions as part of Waves Two and Three. Most customers who provided an answer to the first question: *"Given what you've heard today, do you accept that an improvement in reliability risk comes at a cost"*, answered yes. Most answered no when asked if they will accept a rate increase for a transmission system plan where reliability risk still increases. Over half of those who answered the question about whether they will accept a rate increase for a transmission system plan where reliability risk is unchanged answered no. Well over half of those who answered the question about whether they will accept a rate increase for a transmission system plan where reliability risk improves answered yes.

RELIABILITY RISK VS. RATES TRADE-OFF



Base: Wave 2 and Wave 3 participants who responded to the question (n=22-30)

NOTED DIFFERENCES BY CUSTOMER SEGMENTS

LDCs

LDCs are concerned about how the ratepayers in their region will respond to an increase in transmission rates. Their ratepayers have a hard time understanding the difference between transmission and distribution rates, and the LDCs expressed concern that their ratepayers may not be willing to accept an increase in rates for improved reliability even if the LDC feels it is beneficial.

As it relates to asset management, most LDCs are in agreement with Hydro One because they are also tasked with assessing their aging assets and making decisions around investment plans and accompanying rate increases.

With regard to the illustrative investment scenarios, LDCs expressed skepticism and concern that Hydro One would be able to ramp up as needed for the amount of asset work they are proposing both internally and as it relates to workers in the field. The general consensus for Scenario 3 is that there would be a need to hire third party workers in order to complete the necessary work on lines.

In summary, while LDCs recognize and appreciate the need for rate increases to fund asset investments, they are wary of large rate increases as these are passed along to the ratepayers, who are sensitive to the bottom line on their bills.

LARGE INDUSTRIAL BUSINESSES

Reliability is the most important and pressing concern for large industrial businesses such as automotive manufacturers, mines, and mills. Unplanned service interruptions have dire financial consequences for many in this group where lost productivity costs run into the tens of millions. There are also safety considerations for mine and mill workers where they have to manually re-set machinery.

Secondary concerns for this group are power capacity. This pertains to those large industrial businesses in the North who have a need for additional power but are unable to generate it themselves or obtain it through the current transmission system – that is, they have been unable to find a solution through Hydro One or other means.

Some of these customers expressed positive feedback about the day-to-day communication and customer service they receive from their area representatives, but have concerns that Hydro One may not keep up with broader communication about its long-term planning.

Rate increase sensitivity is less of an issue with this group who depend on reliable good quality power to be competitive and successful in their businesses.

GENERATORS

For nuclear generators, their primary concern is safety. They feel that they are a core, essential service to the province and that any work related to reliability that directly affects them should be a top priority.

Additionally, they would like to know how planned outages will affect their ability to generate. Cooperation around scheduling is very important.

In terms of rate increases, they are less sensitive as safety and reliability are their key concerns. Additionally they recognize that investing in the short term to address reliability risks means better reliability in the long term. One generator indicated that for them the scenarios were too reactive, and in fact not forward-looking enough.

NOTED DIFFERENCES BY GEOGRAPHY

NORTHERN ONTARIO

Customers in the North who are more likely to be on single circuit supply tend to experience more frequent unplanned interruptions than those in the South and the cost implications are enormous. There are also safety considerations for these huge operations when an interruption occurs. At the same time, they recognize the challenges presented by the physical landscape of their region for maintenance and sustainment work.

SOUTHERN ONTARIO

Since customers in Southern Ontario are more likely to be on multi-circuit supply, they experience fewer unplanned service interruptions than their counterparts in the North. Therefore, the need for improved reliability risk was somewhat less pressing for them and it makes the case for increasing rates to improve reliability more difficult.

Furthermore, they struggle more with the idea of system-wide asset management and how the investment plan would benefit them directly.

Some LDCs are aware of and sensitive to the challenges faced by Hydro One as it relates to urban expansion and space restrictions, and the complex nature of maintenance and sustainment work as a result. The LDCs that mentioned this also communicated their willingness to cooperate with Hydro One in order to minimize customer vulnerability as it relates to planned outages.

Most large industrial customers, as well as nuclear generators, believe that an increase in rates for better reliability is worthwhile regardless of region; however as stated above, this region experiences better reliability and are therefore more sensitive to rate increases.

PART C: FEEDBACK ON THE CONSULTATION PROCESS

Waves Two and Three wrapped up by posing a few questions to customers about the usefulness of the consultation process, and the extent to which they believed their feedback was captured and heard. Customers were also asked if they think Hydro One should hold this type of broader customer consultation in the future and if so how often.

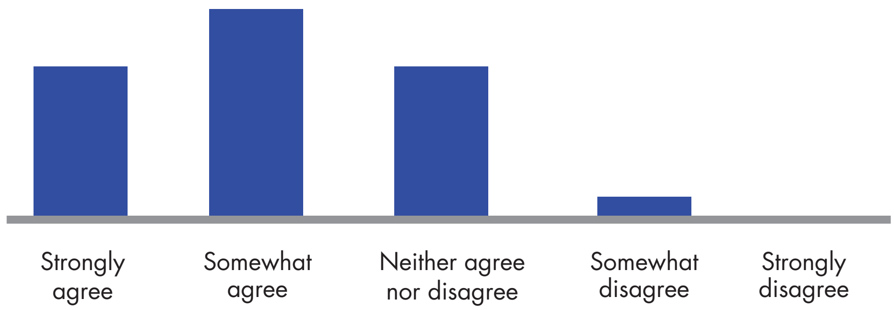
It was explained to customers that a broader customer consultation would be in addition to one-on-one local discussions that will continue to occur on a project-by-project basis.

FEELING HEARD

Q. I feel my feedback was heard today regarding Hydro One's approach to investment planning?

Most customers across the consultation activities indicated that that their feedback was heard, and some expressed confidence that their input will be incorporated into Hydro One's investment plan. Others were doubtful that their input would have much impact on decision-making within Hydro One. Customers acknowledged that this type of discussion would not have happened 10 years ago and they welcome the opportunity to hear more about Hydro One's plans for the future.

ADDRESSING RELIABILITY RISKS VS. DEFERRING INVESTMENT



I feel my feedback was heard today regarding Hydro One's approach to investment planning.
Base: Wave 2 and Wave 3 participants who responded to the question (n=27)

"I am happy to see what has happened today. The success of this meeting is based on how far our feedback gets. I want to see some active changes and discussion based on meetings as a whole. The plan needs to morph to be a success. If all this does that confirms what it is in the plan then a waste of time. I'm happy to be part of this as long as portions of discussion make it through the system."

"They do a good job of getting workshops together, it's fantastic content. They're leading the discussion on multiple fronts. The problem is no one has the answer."

GETTING TO THE RIGHT ISSUES

Q. Based on everything you saw and heard today, did the session get to the right issues?

Opinions were mixed on the extent to which the sessions got to the right issues, or achieved sufficient detail on the issues that customers feel are important to the investment plan in order to make a judgement on their preferred investment plan.

"We think that Hydro One does a good job on consultation and leading the discussion on all fronts. There are no answers to all of this. It is hard to say if they are being proactive in their investment, but [Hydro One is] proactive in their discussion of the risk. Hydro One is having the correct conversation."

"Sort of – seems the questions asked are grouped from Hydro One's perspective and not the end user perspective."

"I think it is important to include the expected rate impact based on all costs – seeing cost control is our customers' focus and the focus of the province to promote business in Ontario. Without knowing the total rate impact, forming an opinion is difficult."

FREQUENCY OF GROUP CONSULTATION SESSIONS

Q. How often do you think Hydro One should hold these sessions?

There was a general consensus that Hydro One should hold sessions like this annually and most customers indicated that they would personally be willing to participate in future meetings. A few commented that they would prefer to conduct the sessions semi-annually.

"If people in the industry hear of change coming from these types of meetings then you will get better attendance."

APPENDIX

APPENDIX

CONSULTATION PARTICIPANT LIST

Wave One – One-on-One Consultations

Adel Ali, General Motors of Canada Ltd.
Michael Angemeer, Veridian Connections Inc.
David Bench, Domtar Inc.
Angelo Boschetti, Toronto Hydro-Electric System Limited
Paul Boucher, Bruce Power L.P.
Kevin Brad, Nova Chemicals (Canada) Ltd.
Terry Britton, Veridian Connections Inc.
Joe Cooper, Domtar Inc.
Ralph Cote, Bruce Power L.P.
Mike Demsky, General Motors of Canada Ltd.
Laurie Elliot, Hydro Ottawa Limited
Derek Francis, Suncor Energy Inc.
Dave Garland, Hydro Ottawa Limited
Peter Giardetti, Resolute FP Canada Inc.
Jeff Hansen, Ontario Power Generation
Mark Hiseler, Suncor Energy Inc.
Ed Johnston, Veridian Connections Inc.
Tom Lacey, Nova Chemicals (Canada) Ltd.
Anthony Lachance, Domtar Inc.
Remi Lalonde, Resolute FP Canada Inc.
Bryan Lewis, Domtar Inc.
Shawn Li, Toronto Hydro-Electric System Limited
Greg Lubertowicz, Arcelormittal Dofasco Inc.
Robert Mace, Thunder Bay Hydro Electricity Distribution Inc.
Ivan Matthews, Hydro Ottawa Limited
Eric McCarthy, Ontario Power Generation
Brian McLauchlan, Domtar Inc.
Jay Mitroff, Domtar Inc.
Jim Pegg, Hydro Ottawa Limited
Peter Petriw, Veridian Connections Inc.
Rich Remple, Suncor Energy Inc.
Janice Salter, Ontario Power Generation
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Sushil Shah, Ontario Power Generation
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Craig Smith, Veridian Connections Inc.
Robert Swanstrom, Suncor Energy Inc.
Rob Thompson, Nova Chemicals (Canada) Ltd.
Tom Thompson, Nova Chemicals (Canada) Ltd.
Mike Weatherbee, Veridian Connections Inc.
Doug Yates, General Motors of Canada Ltd.

APPENDIX

CONSULTATION PARTICIPANT LIST

Wave Two – Large Group Consultations

Kevin Bailey, Welland Hydro-Electric System Corp.
Mike Block, Peterborough Distribution Inc.
Tom Brackenbury, Kingston Hydro Corporation
Jake Brooks, Association of Power Producers of Ontario
Darren Brown, Goldcorp, Musselwhite
Jim Brown, EnWin Utilities Ltd.
Carolyn Bultena, GDF Suez Canada Inc.
Tim Clutterbuck, ASW Steel Inc.
Tim Curtis, Niagara-on-the-Lake Hydro
Robert Evangelista, Hydro One Brampton Networks Inc.
Dave Forsyth, Gerdau Long Steel North America
Al Gereghty, Vale Canada Ltd.
Paul Gleason, EnWin Utilities Ltd.
Phil Guido, Greater Sudbury Hydro Inc.
Herbert Haller, Waterloo North Hydro Inc.
Jie Han, FortisOntario Inc.
Howard Holland, Goldcorp, Musselwhite
Brian Koltun, Vale Canada Ltd.
Andy Mahut, US Steel Canada Inc.
Jim Miller, Kingston Hydro Corporation
Brad Millroy, London Hydro Inc.
Riaz Shaikh, PowerStream Inc.
Ismail Sheikh, London Hydro Inc.
Mark Simpson, Brantford Power Inc.
David Smelsky, Halton Hills Hydro Inc.
Cole Tavener, London Hydro Inc.
Kerry Taylor, Greater Sudbury Hydro Inc.
Allan Van Damme, London Hydro Inc.
Mark Van de Rydt, Greater Sudbury Hydro Inc.
Dennis Visintin, AV Terrace Bay Inc.
Tom Wasik, Hydro One Brampton Networks Inc.
Dave Wilkinson, Waterloo North Hydro Inc.
Hooman Zamani, Kirkland Lake Gold Inc.

APPENDIX

CONSULTATION PARTICIPANT LIST

Wave Three – Self-Directed Online Consultation Tool

This list includes individuals who logged in to the Wave Three online consultation tool but did not respond to any questions.

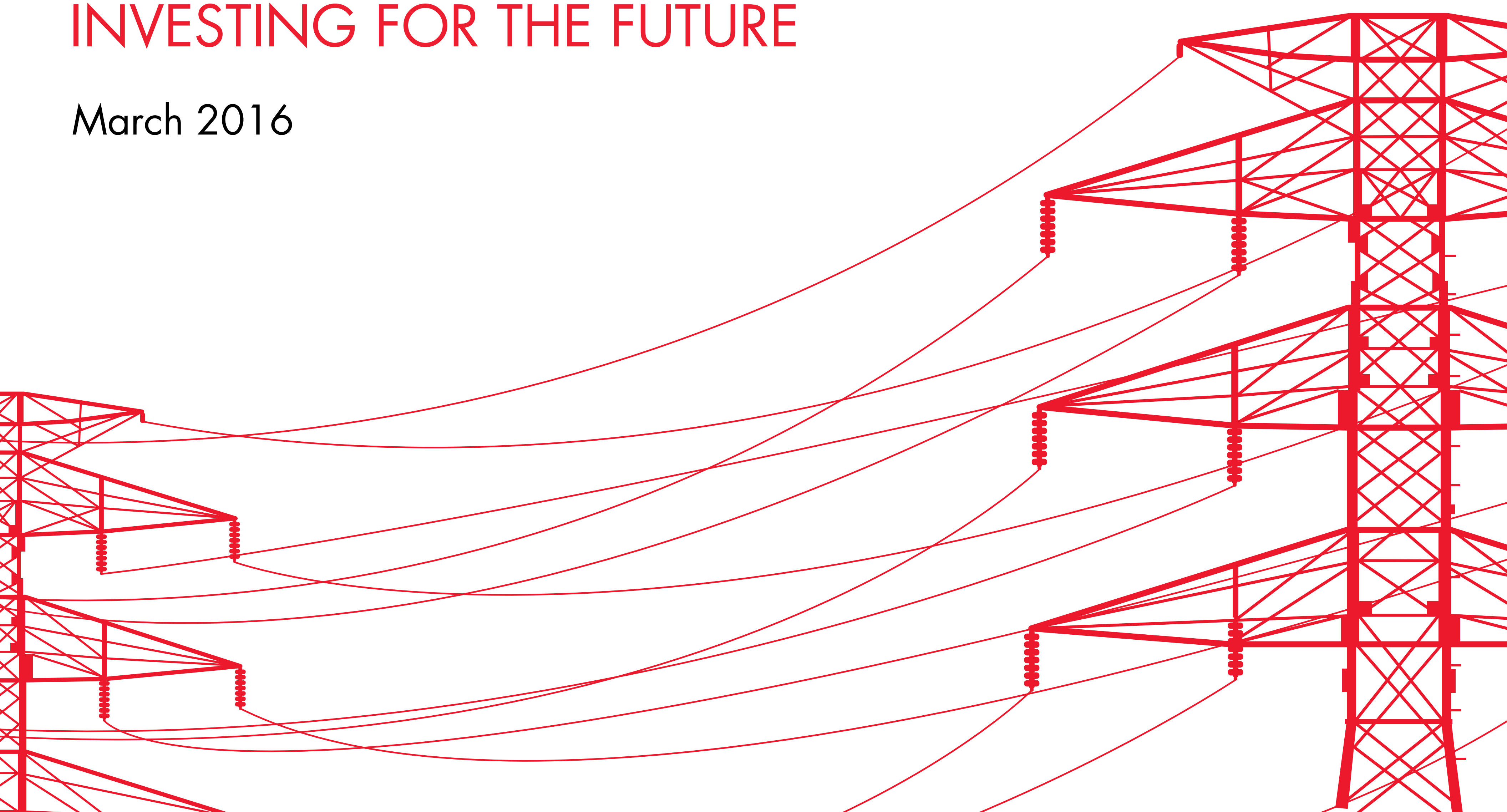
Adel Ali, General Motors of Canada Ltd.
Gerry Bernard, Tembec Enterprises Inc.
John Brace, McLean's Mountain Wind L.P.
Jake Brooks, Association of Power Producers of Ontario
Darrell Brown, Goldcorp, Musselwhite
Jim Brown, EnWin Utilities Ltd.
Robert Chercoe, National Research Council of Canada
J.J. Davis, Kruger Energy Port Alma Limited Partnership
Shawn DeForge, AuRico Gold Inc.
Joe Emberson, McMaster University
Robert Evangelista, Hydro One Brampton Networks Inc.
Ryan Forget, Atlantic Power L.P.
Sean Gillespie, Atlantic Power L.P.
Jeff Glaser, Panabrasive Inc.
Ben Greenhouse, Summerhaven Wind, L.P.
Rodney Guy, Greater Sudbury Hydro Inc.
Herbert Haller, Waterloo North Hydro Inc.
Paul Heeg, Haldimand County Hydro Inc.
Jim Huntington, Niagara-On-The-Lake Hydro Inc.
Irv Klajman, PowerStream Inc.
Gerry Landriault, FQM (Akubra) Inc.
Greg Lubertowicz, Arcelormittal Dofasco Inc.
James Macumber, Enersource Hydro Mississauga Inc.
Gary Mayne, ASW Steel Inc.
Robert Mozzoni, Goreway Station Partnership
Marianna Nagy, U.S. Steel Canada Inc.
Mike Ploc, Peterborough Distribution Inc.
Claude Quesnel, Greater Sudbury Hydro Inc.
Ismail Sheikh, London Hydro Inc.
Michael Shuman, Kirkland Lake Gold Inc.
Mark Simpson, Brantford Power Inc.
Dave Stevens, Lake Shore Gold Corp.
Derek Teevan, Detour Gold Corporation
Patricia Vallejo, Next Era Energy Canada
Jason Weir, Suncor Adelaide Wind Limited Partnership
Kevin Whitehead, Whitby Hydro Electric

PRESENTATION TO CUSTOMERS INCLUDING DISCUSSION GUIDE

TRANSMISSION CUSTOMER ENGAGEMENT:

INVESTING FOR THE FUTURE

March 2016



CONFIDENTIAL AND FORWARD-LOOKING INFORMATION

CONFIDENTIAL INFORMATION

In this presentation, "Hydro One" or "the Company" refers to Hydro One Networks Inc. and its affiliates, taken together as a whole.
Hydro One is providing the information contained in the following presentation on a confidential basis in order to solicit your feedback on potential alternate investment scenarios and their expected impact on the reliability of our transmission system. The feedback from this customer consultation will be considered when making regulatory filings. Any information concerning Hydro One provided as part of this presentation should not be disclosed except as necessary within your corporation in order to provide meaningful feedback.

You should not trade in securities of Hydro One Limited or Hydro One Inc. based on any of the information contained within this presentation and should not use the information for any other purpose.

In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of Hydro One is intended only to illustrate past performance and is not necessarily indicative of future performance.

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This presentation contains "forward-looking information" within the meaning of applicable Canadian securities laws. Forward-looking information in this presentation is based on current expectations, estimates, forecasts and projections about Hydro One's business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: statements regarding expected or projected capital and development expenditures, the timing of these expenditures and the Company's investment plans; the use of customer feedback from the consultation process and its impact on the Company's investment plans; the impact of future investments on customer risk, reliability performance and risk, and service interruptions; statements about asset condition, the average ages of critical assets, and their future expected condition; statements about types of asset replacements and their expected associated costs; and statements about illustrative scenarios and their impact on capital spend, expected outcomes, rates, changes in risk profile according to asset class, and increased or decreased system risk impact.

Words such as "aim", "could", "would", "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "target", "project" and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

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AGENDA

INTRODUCTION: CONTEXT AND OBJECTIVES

REVIEW: SYSTEM PERFORMANCE

DISCUSSION: INVESTMENT SCENARIOS

WHO WE ARE AND WHAT WE DO

hydro one

Hydro One
is one of the largest transmission utilities in North America.

We cover more than **640,000 km²** which is twice the size of France.

Our system is the backbone of Ontario's electricity ensuring safe and reliable power is available for the homes and businesses of Ontario.

Hydro One covers some of the most challenging and diverse geography in Canada. Hydro One's system transmits electricity from generation sources to our customers.

Hydro One's transmission customers across Ontario include 47 transmission-connected local distribution companies (LDCs), Hydro One's distribution system, and 90 large industrial customers directly connected to the transmission system.

Hydro One's transmission system totals approximately 292 transmission stations and approximately 29,000 circuit kilometres of high-voltage lines, towers and transformers, operating at 500 kV, 230 kV or 115 kV. It represents ~$12B in assets.

WHO WE ARE AND WHAT WE DO

In 2015, Hydro One transported 137 TWh of electricity.

The transmission system is linked to five jurisdictions adjacent to Ontario: Manitoba, Minnesota, Michigan, New York and Quebec through high-voltage interconnections.

It is part of North America's Eastern Interconnection and must comply with standards established by the North American Electric Reliability Corporation (NERC).

Hydro One's transmission operations are regulated by the Ontario Energy Board (OEB) and the National Energy Board (NEB), together with an operating agreement with the Independent Electricity System Operator (IESO).

WE TAKE A RISK-BASED APPROACH TO INVESTMENT

We are accountable to plan, operate, build, and maintain an affordable, robust and flexible transmission system that **serves Ontario's needs** and meets our obligations as part of the North American grid.

Our investment plan will identify, prioritize, and schedule the investments we make in our system. On this basis, we aim to create value by:

- Ensuring our investment plan considers and reflects the needs and preferences of our customers by achieving a balance between managing reliability risk, service and cost.
- Recognizing every dollar we spend comes at a cost to our customers and the people of Ontario.
- Making prudent, cost-effective, short and long-term investments in our transmission system so that the electricity needs of Ontario are met now and into the future.
- Addressing emerging risks of our system, and always looking for ways to economically extend the life of existing transmission assets.
- Being innovative by adapting new/proven technologies, equipment and processes that contribute to the efficiency of our operation.

OUR CUSTOMER ENGAGEMENT PROCESS

Hydro One is in the process of **developing its Transmission Investment Plan** for 2017 and beyond.

This investment plan will in turn, underpin our **Transmission Rate Application** to the OEB later this spring.

Our Investment Plan will be based on our customers' needs and preferences, our analysis of assets' needs and of our ability to resource, schedule and execute work.

All transmission-connected customers will have the opportunity to provide input that will support the development of the Investment Plan through:

- One-on-one discussions
- Larger, professionally facilitated customer engagement sessions held in Toronto, London, Ottawa, Thunder Bay, and Sudbury
- An online survey

The approach we are taking is consistent with the OEB's Renewed Regulatory Framework.

AGENDA

INTRODUCTION: CONTEXT AND OBJECTIVES

REVIEW: SYSTEM PERFORMANCE

DISCUSSION: INVESTMENT SCENARIOS

SUMMARY OF SYSTEM PERFORMANCE

Hydro One's transmission reliability has remained flat.

The **transmission system faces increasing challenges** due to asset condition.

Equipment performance is the largest controllable factor, contributing 42% of system *interruption*[1] minutes. Assets continue to age (e.g., 20% of conductors now beyond *expected service life*[2] of 70 years).

Evidence suggests that underlying reliability risk is increasing:

- Equipment outages[3] caused by failure or necessary repairs/replacements increased ~300% from 2011 – 2015.
- Increased duration of placing customers, normally served by a multi-circuit system[4] on single supply, increasing interruption risk by ~400%.

Condition assessments have identified critical replacement needs, for example:

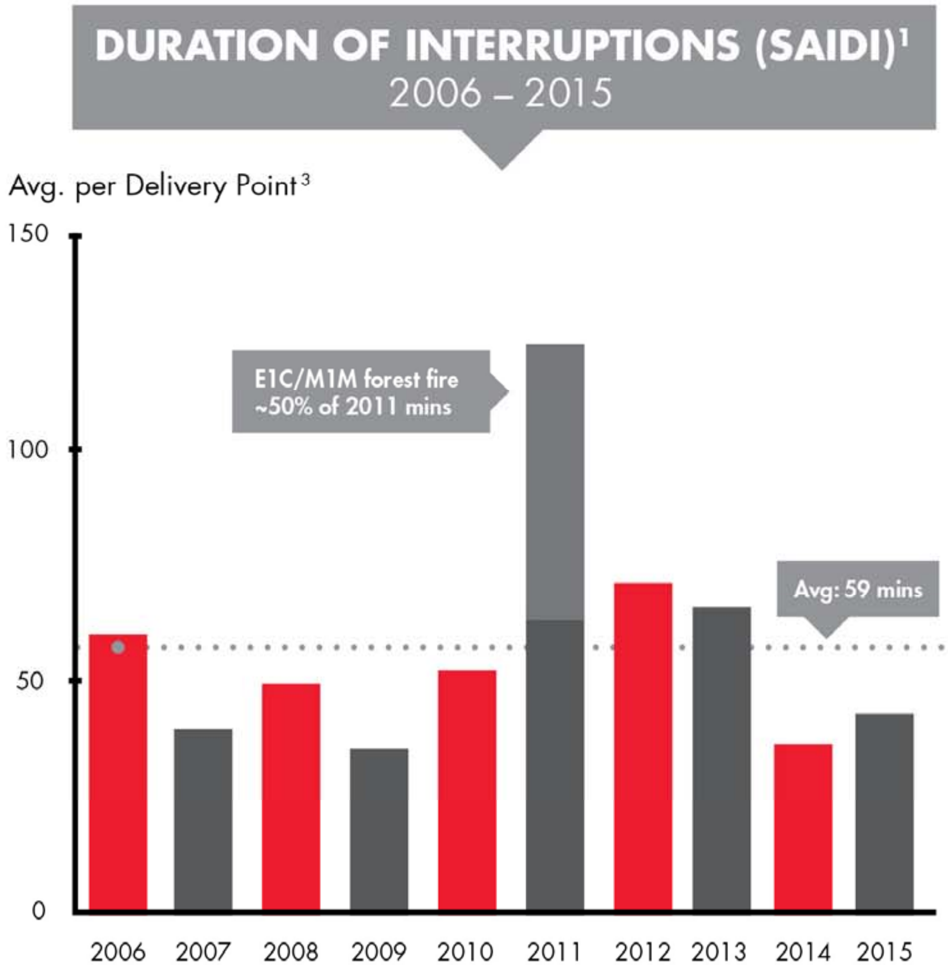
- 2,300 cct-km of conductors identified for priority replacement due to being at or near end of useful life[5].
- 9,100 steel towers at heightened failure risk due to depletion of their corrosion protection layer.

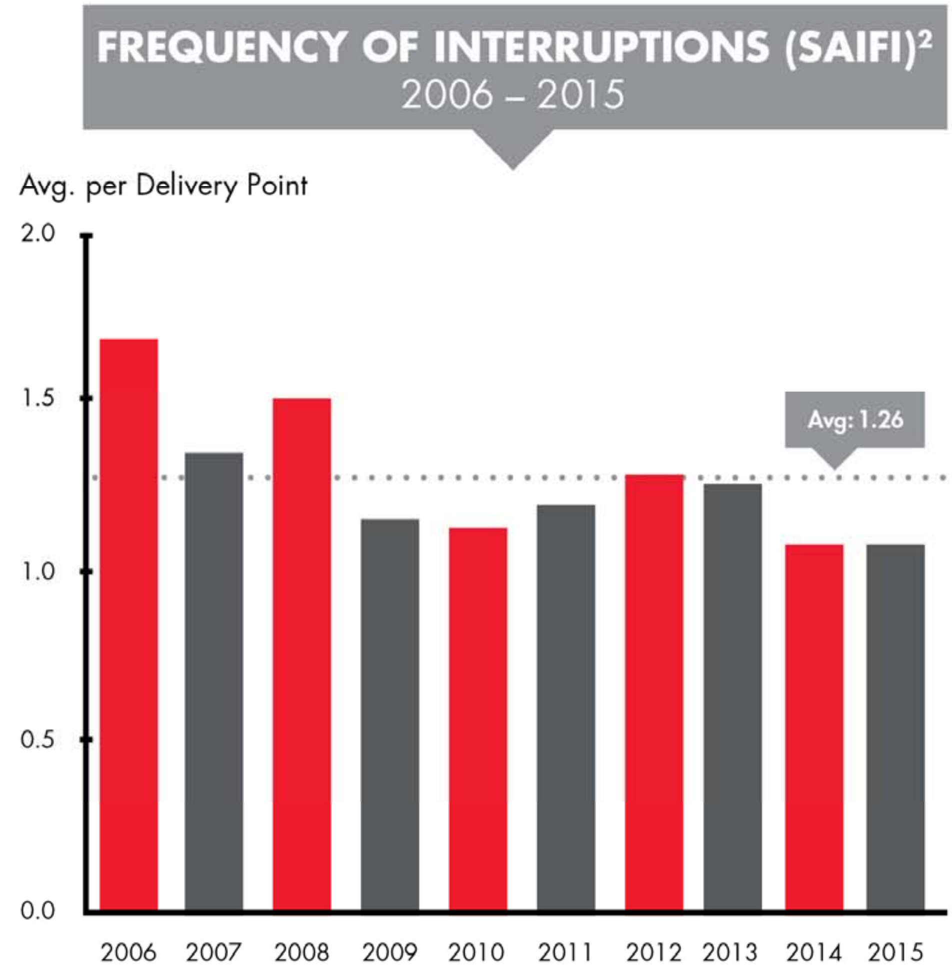
Hydro One continues to take action to mitigate reliability risk by:

- Managing equipment performance through robust, condition-based asset replacement programs.
- Reducing customer exposure to single-supply through improved planning and work processes.

1. Outages on the transmission system that interrupt the supply of energy to transmission customers.
2. The average time in years that an asset can be expected to operate under normal system conditions.
3. The removal of facilities from service, unavailability for connection of facilities, temporary de-rating, restriction of use or reduction in the performance of facilities for any reason, including to permit the inspection, testing, maintenance or repair of facilities.
4. Delivery points served by multiple transmission circuits, creating system redundancy; tend to be located in the southern areas of the province.
5. As asset-specific determination based on an asset's condition, criticality, performance, demographics, utilization and economics.

OVERALL TRANSMISSION RELIABILITY HAS REMAINED FLAT





Note: Includes both sustained and momentary interruptions. Excludes planned interruptions and interruptions due to customer activity. Excludes 2013 GTA flood (extreme Force Majeure event - a natural consequence of external forces that are beyond reasonable control).

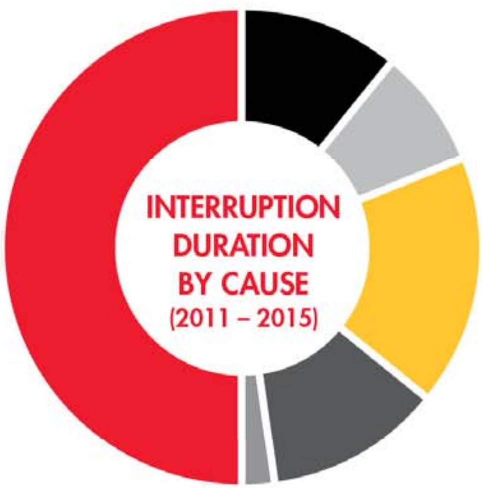
1. System Average Interruption Duration Index
2. System Average Interruption Frequency Index
3. Interface between the Hydro One transmission system and its load customers. Delivery points consist of: (a) all Hydro One owned step-down transformer stations' low-voltage buses, and (b) stations owned by end-use transmission customers, including LDCs and other transmitters operating at 115kV or higher.

EQUIPMENT PERFORMANCE AND DRIVERS VARY ACROSS MULTI-CIRCUIT AND SINGLE-CIRCUIT SYSTEMS (2011-2015)

Equipment failure is the single largest driver of customer interruption minutes across both systems.

MULTI-CIRCUIT SYSTEM (SAIDI)

KEY FACTS:
- ~70% of delivery points
- ~85% of total load
- Located primarily in Southern Ontario



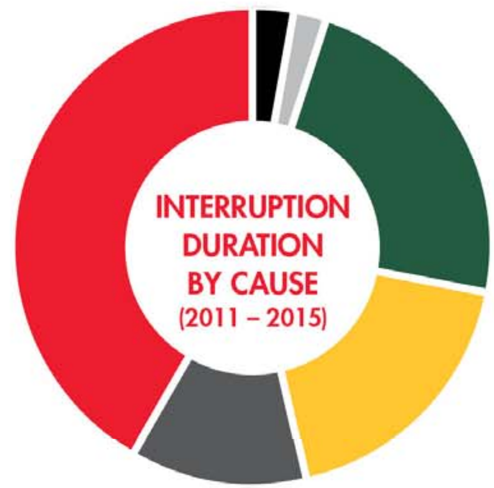
- 50% Equipment
- 17% Weather
- 12% Foreign
- 11% Power System
- 2% Human
- 0% Environment
- 8% Unknown/Other

Average interruption duration per delivery point: **10 mins**

Duration of interruptions limited by redundancy in the multi-circuit network

SINGLE-CIRCUIT SYSTEM (SAIDI)[1]

KEY FACTS:
- ~30% of delivery points
- ~15% of total load
- Located primarily in Northern Ontario



- 41% Equipment
- 18% Weather
- 13% Foreign
- 13% Power System
- 0% Human
- 23% Environment *Includes 2011 forest fire*
- 2% Unknown/Other

Average interruption duration per delivery point: **211 mins**

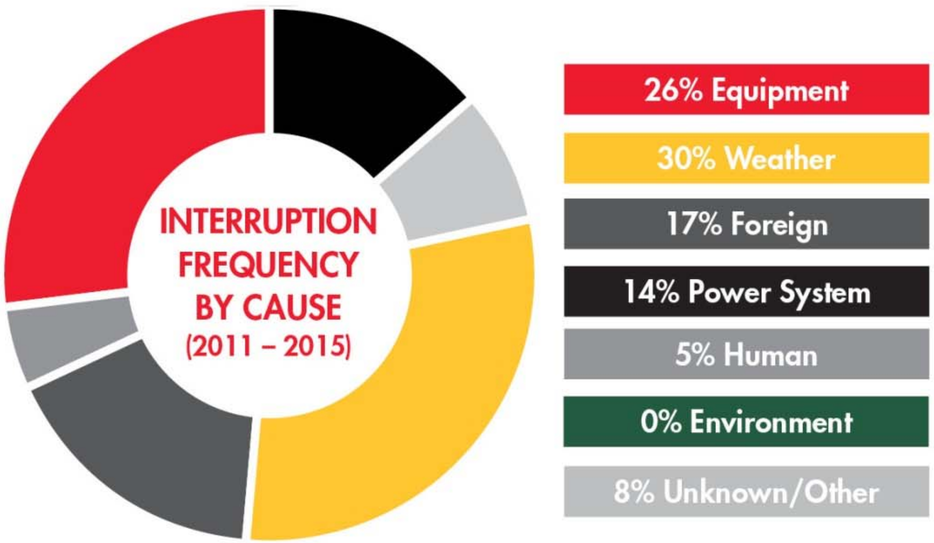
Lack of redundancy drives increased duration of interruptions

Note: Excludes planned interruptions and interruptions due to customer activity. Excludes Force Majeure events.
1. Delivery points served by sole transmission circuit, leading to limited redundancy; tend to be located in the northern areas of the province.

SAIFI CONTRIBUTION BY CAUSE (2011-2015)

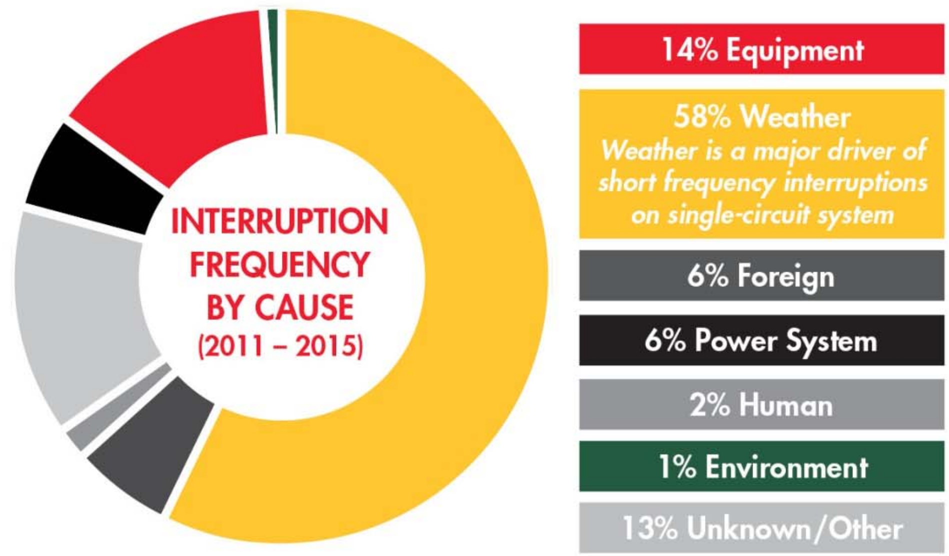
MULTI-CIRCUIT (SAIFI)

Average frequency per delivery point: 0.27



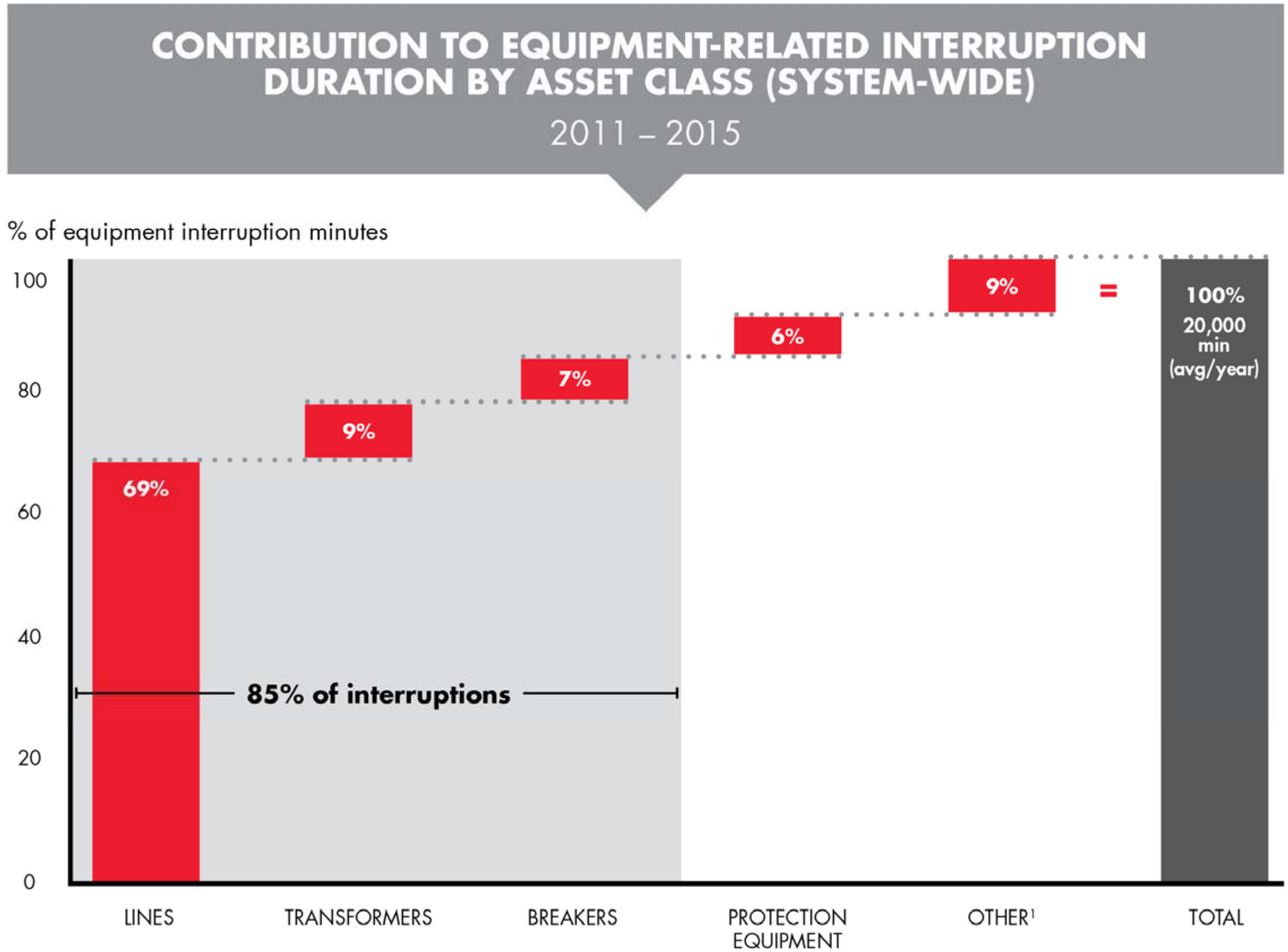
SINGLE-CIRCUIT (SAIFI)

Average frequency per delivery point: 1.51



Note: Includes both sustained and momentary interruptions. Excludes planned interruptions and interruptions due to customer activity. Excludes interruptions due to Force Majeure events.

LINES, TRANSFORMERS AND BREAKERS ACCOUNT FOR 85% OF EQUIPMENT-RELATED INTERRUPTION DURATION

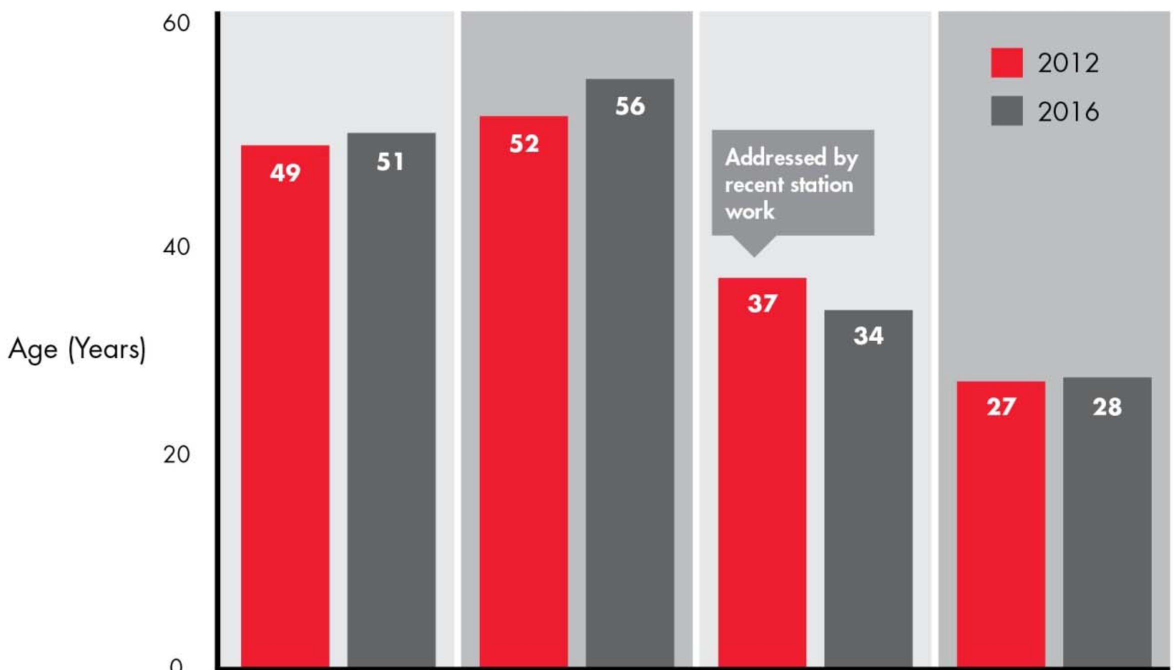


1. Other includes switches, instrument transformers, surge arrestors, system auxiliaries

THE AVERAGE AGE OF CRITICAL ASSETS HAS INCREASED IN RECENT YEARS, AND TESTING HAS IDENTIFIED PRIORITY ASSETS FOR REPLACEMENT

hydro one

HISTORICAL REPLACEMENT RATE HAS BEEN INSUFFICIENT TO ADDRESS SYSTEM AGING...



	CONDUCTORS	STEEL TOWERS	TRANSFORMERS	BREAKERS
% beyond expected service life[1]	20%	22%	28%	9%
# beyond expected service life	5,800 cct-km	12,000	203	399

+

CONDITION ASSESSMENTS HAVE IDENTIFIED SPECIFIC ASSETS FOR REPLACEMENT.

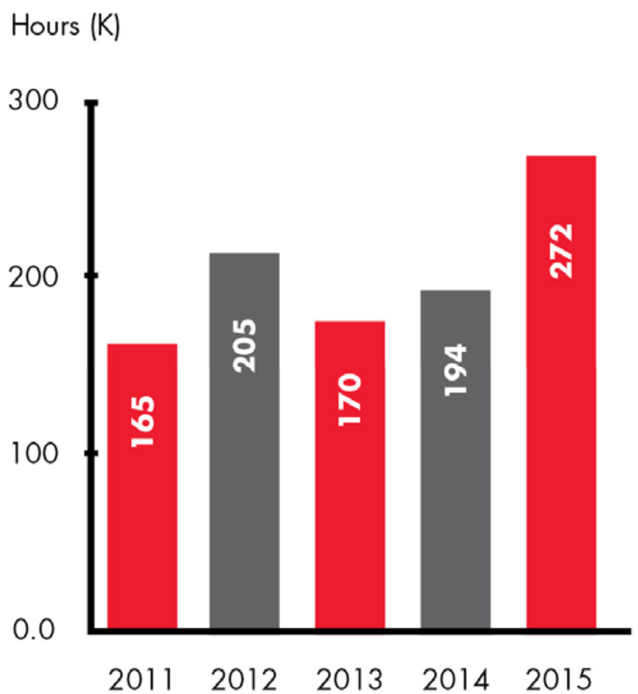
ASSET	CONDITION
CONDUCTORS	• Based on actual conductor sample testing, 2,300 cct-km of transmission lines known to be at or approaching end of useful life
STEEL TOWERS	• 9,100 steel structures located in known high-corrosion areas based on inventory assessment
TRANSFORMERS	• 31 transformers (4.3%) rated high-risk or very high-risk based on condition assessment
BREAKERS	• ~470 breakers rated high-risk or very high-risk based on condition assessment
INSULATORS	• ~25% of insulators at greater risk of failure • Ongoing testing will determine remaining insulator strength

1. The average time in years that an asset can be expected to operate under normal system conditions.

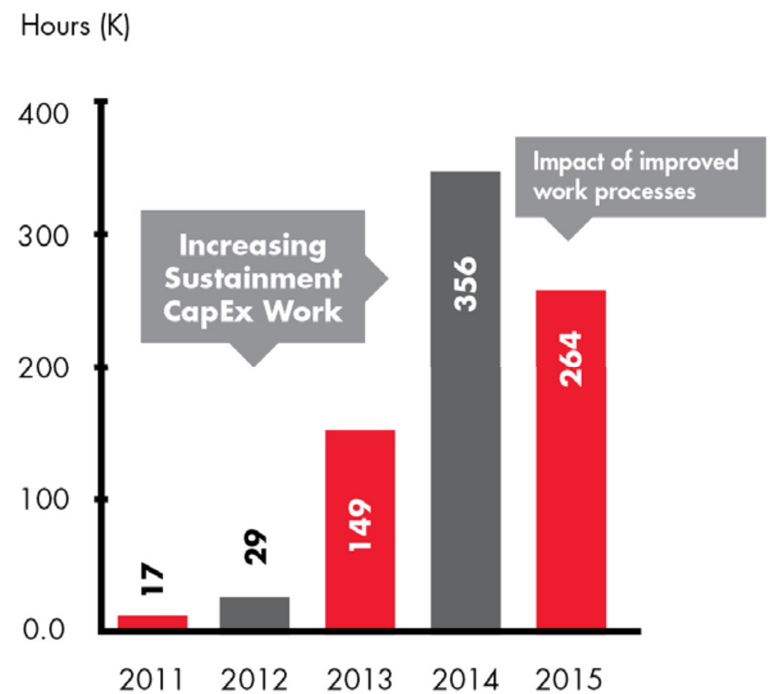
ASSET CONDITION IS INCREASING OUTAGES ACROSS THE SYSTEM

hydro one

1 UNPLANNED OUTAGE HOURS DUE TO EQUIPMENT FAILURE[1]
(system-wide)



2 PLANNED OUTAGE HOURS FOR EQUIPMENT REPAIR/REPLACEMENT[2]
(system-wide)



Implications of outages:

Single-circuit system:
Increased duration of interruptions

Multi-circuit system:
Greater time on single supply → increased interruption risk

1. Includes direct outages caused by power equipment or protection equipment failure
2. Includes total duration of planned outages designated as for repair or replacement across all equipment types

HYDRO ONE IS UNDERTAKING A NUMBER OF ACTIONS TO MITIGATE RELIABILITY RISK

ONGOING ACTIVITY TO ADDRESS RELIABILITY RISK

1 Unplanned Outages: Equipment Failure

The risk due to unplanned outages is being managed by:

- Continued focus on asset condition assessments and data-driven risk analysis
- Assessing maintenance programs and CapEx spend vs. transmission reliability contributions from asset classes
- Evaluating assets that may be run–to-failure candidates (those not directly affecting transmission reliability)

2 Planned Outages: Equipment Repair and Replacement

The risk due to planned outages is being managed by continued prudent planning and work processes, such as:

- Station-centric work approach
- Re-evaluating maintenance program cycles
- Focusing on identifying and enabling work bundling opportunities
- Transmission System Outage Groups process
- Multi-disciplinary planning
- Pre-outage inspections on companion assets (e.g., transformers) for multi-circuit outage requirements

AGENDA

INTRODUCTION: CONTEXT AND OBJECTIVES

REVIEW: SYSTEM PERFORMANCE

DISCUSSION: INVESTMENT SCENARIOS

DISCUSSION

Recent changes that have occurred include...

- New management and independent Board of Directors
- Better line of sight to specific system risks and new approaches to address certain risks
- Benchmarking suggests that Hydro One's total spending on its transmission system has been less than comparators
- Greater clarity from the Ontario Energy Board on the Renewed Regulatory Framework for Electricity as it relates to transmitters

INVESTMENT SCENARIOS

Illustrative scenarios have been developed for various levels of sustainment expenditures.

These in turn, **result in different rate impacts and reliability risks.**

These scenarios focus on the Sustainment Capital portion of our Investment Plan and are meant to represent a spectrum of potential investments.

We do not have a recommended scenario, nor are we asking you to choose from the scenarios presented.

The asset solutions identified are flexible. The inclusion and pacing of investments in the plan may vary from what is presented in the scenarios.

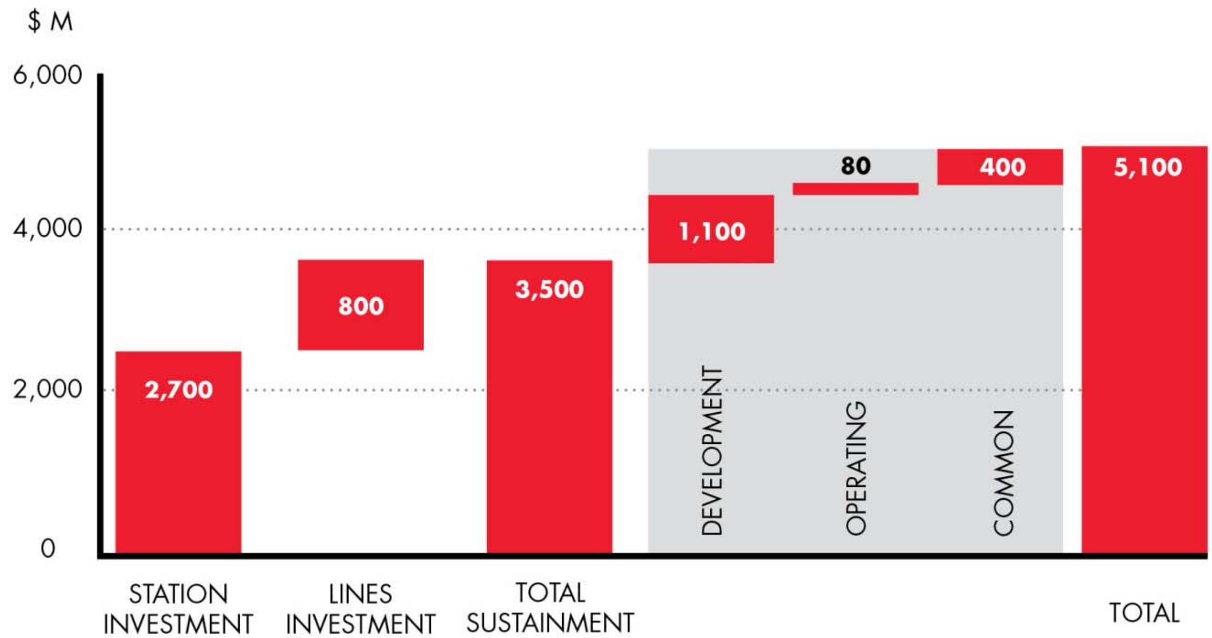
Through this conversation, we would like to better understand your business needs and preferences to inform our 5-year Investment Plan.

SCENARIO ONE

SCENARIO 1
~$5,100M (2016 – 2020)

KEY ELEMENTS OF SCENARIO 1

- Coordinated replacement of multiple elements at stations to reduce outages
- Investment to replace high risk air-blast circuit breakers
- Replacement of aging transformer population
- Does not fully address increasing risk due to line asset aging/conditions



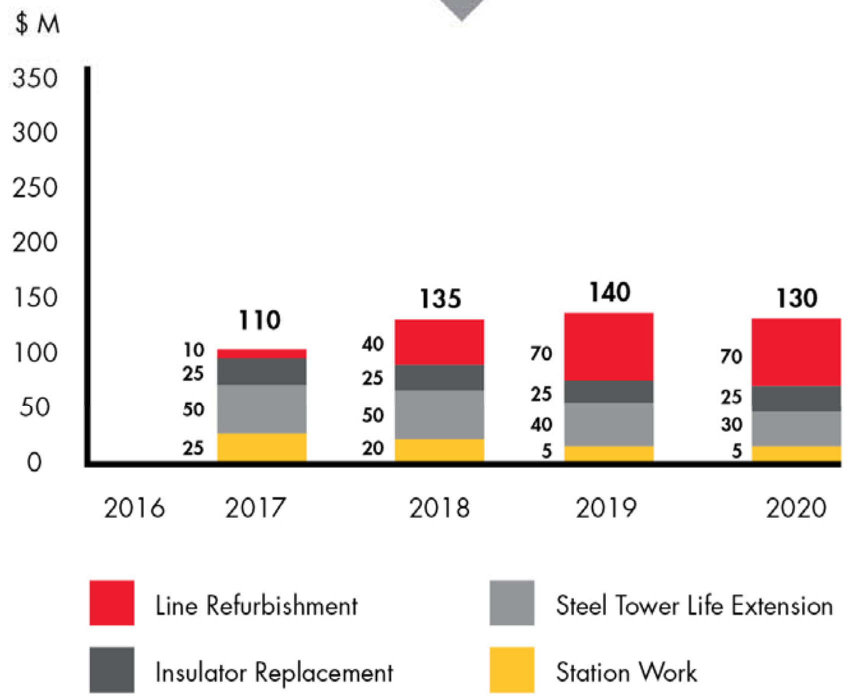
Overall risk profile:
Reliability risk expected to increase

SCENARIOS TWO AND THREE

hydro one

SCENARIO 2

~$520M in incremental CapEx from 2016 – 2020

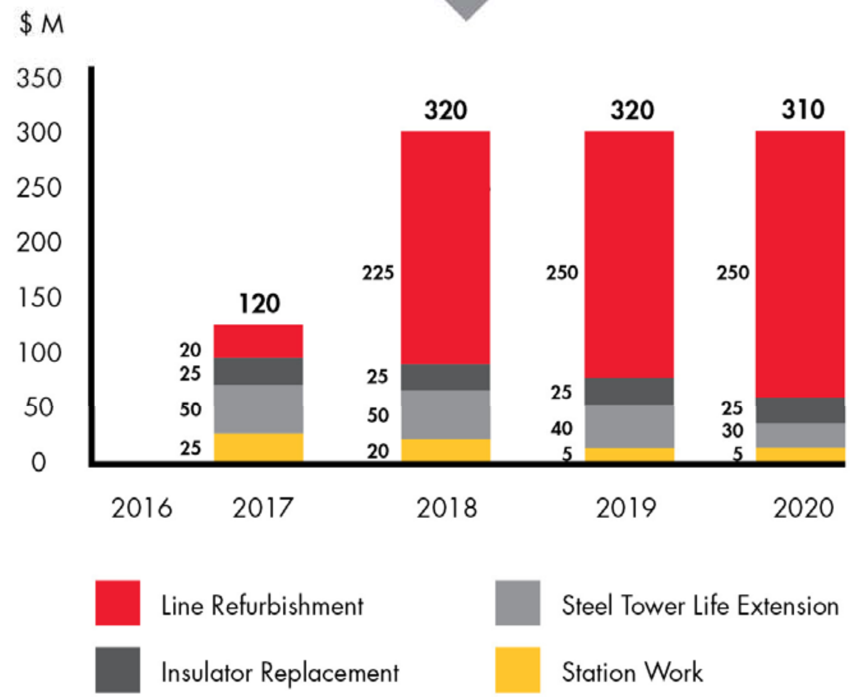


- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 1,200 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Current reliability risk expected to remain unchanged

SCENARIO 3

~$1.1B in incremental CapEx from 2016 – 2020



- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 2,300 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Reliability risk expected to decrease

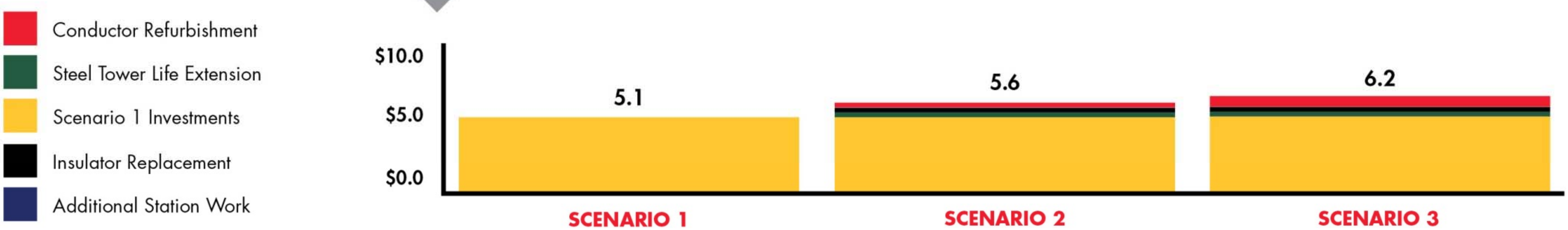
SCENARIOS BASED ON FOUR MAJOR ASSET REPLACEMENT PROGRAMS

	DESCRIPTION	RATIONALE
STATION WORK	Additional replacement of air-blast circuit breakers (ABCB) with new SF6[1] breakers	• Air-blast circuit breakers known to have 5-7x higher likelihood of unplanned outage than new SF6 breakers • ABCB is an obsolete technology and manufacturers will cease support by 2020
LINE REFURBISHMENT	Accelerated replacement of lines, based on asset condition	• 20% of conductors beyond end of service life (70 years) will reach ~40% by 2024 under historic replacement rates • Historic average replacement rate of 60 cct-km lags rate required to maintain system age • Condition assessments of conductor fleet identified 2,300 cct-km conductors are either at or near end of useful life based on actual conductor sample testing
STEEL TOWER LIFE EXTENSION	Coating of select steel tower structures to extend useful life	• 25% of towers located in high-corrosion regions • Corrosion rate for high-corrosion regions is ~10x higher than in lower corrosion regions • 20% of towers in high-corrosion regions are > 80 years old • Coating extends tower life by 25 years, deferring the need for replacement, with a net present value of $100-200M
INSULATOR REPLACEMENT	Replacement of insulators with known increased risk of failure	• Insulators installed between 1965 and 1982 have a known increased risk of failure • The insulator failure in March 2015 in the GTA reinforces the need to accelerate replacement of insulators • Condition testing underway to better quantify increased risk

1. Sulfur hexafluoride breaker

OVERVIEW OF THREE POTENTIAL SCENARIOS

2016 – 2020 Transmission System Net CapEx ($B)



		SCENARIO 1	SCENARIO 2	SCENARIO 3
Capital Spend	Sustainment ($B)	3.5	4.0	4.6
	Development ($B)	1.1	1.1	1.1
	Other ($B)	0.5	0.5	0.5
Expected Outcomes	Frequency and duration of interruptions	▲ Expected increase in line-related interruptions	▶ Some increase in lines risk offset by limiting unplanned outages and improved station performance	▼ Reduce risk from lines and continue to limit exposure to unplanned outages
	Reliability risk[1]	▲ Risk is expected to increase	▶ Current risk expected to remain essentially unchanged	▼ Risk is expected to decrease
Rates	Transmission rate impact (Compound Annual Growth Rate for 2017 – 2020)[2]	▲ ~5.8%	▲ ~6.3%	▲ ~6.8%

1. Reliability risk is a probabilistic calculation based on asset demographics and the historical relationship between its age and its failure or replacement.
2. Excludes impacts of potential changes in load forecast and any potential change to operations and maintenance spending.

ONLINE CONSULTATION TOOL

Session screenshots

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*User ID and Password are case sensitive.

***User ID**

***Password**

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Please use the user id and password you were provided and then login to the system. You'll see your session name listed and then simply click on the session name and you'll move to the session welcome screen and agenda where you'll see additional information about today's session.

Session Landing Page

Ideation Exchange

Session ▾ | Participants ▾ | Help ▾ | Logoff

Location: Session Gallery

Welcome 1 CPA |

Session Gallery

Open Session Click a session to open or join it.

| ● Active | Archived |

	Session Name	Start Date and Time	Group	Created by	Archived
	Hydro One - Transmission Customer Online Survey	March 24, 2016 12:05 PM EST	Ipsos Public Affairs	IR, MJ	No

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Session ▾ Logoff

Location: Agenda

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Agenda

Hydro One - Transmission Customer Online Survey

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Objective

Thank you for taking part in this online survey. You are your own moderator for this session. This is the Agenda page, after each question you will be sent back to this page where you will be able to click on the next question down below.

If you have any questions about the online platform or how to complete a question in the survey, please contact Matt Jones at Ipsos: matt.jones@ipsos.com

Each set of questions will have a reference to a selection of slides in the PowerPoint deck you were provided. Please use those slides as a framework to answer the questions.

Session Landing Page - 2 of 2

Once you have completed the Session Engagement question you can exit by simply closing your browser.

Topics	Activity
Questions - Section 1	
Q1 - Who is taking part today	Questions
Q2 - Your Needs as a Transmission Customer	Questions
Q3 - Hydro One Performance	Questions
Q4 - Customer Challenges and Concerns	Questions
Q5 - Concerns Ranking Exercise	Questions
Q6 - Agree / Disagree - Proactivity	Questions
Questions - Section 2	
Q7 - Review of System Performance	Questions
Q8 - Interruption Awareness Question	Questions
Q9 - Reliability Performance vs. Risk	Questions
Q10 - Concerns About System Reliability Risk	Questions
Questions - Section 3	
Q11 - Scenario Input	Questions
Q12 - Reliability vs. Rates	Questions
Q13 - Organization Risk Management	Questions
Q14 - Hydro One Proactivity	Questions
Stakeholder Engagement Process	
Q15 - Stakeholder Engagement	Questions

Section 1 - Question 1

Q1 - Who is taking part today

Agenda Topic: Questions - Section 1

Instructions:

Please answer the question below using the drop down menu. Once you are done hit Submit and you will be returned to the first page. Then click Q2 to proceed to the next question and repeat.

Help ▶ Save Submit

1. Please tell us if you are: ▼

Section 1 - Question 2

Q2 - Your Needs as a Transmission Customer

Agenda Topic: Questions - Section 1

Instructions:

Enter your thoughts in the text box below and click Submit to finalize your answer. From the main screen, click Q3 to proceed.

Please refer to slides 4-7 in your presentation.

As a transmission customer, what's most important to you to ensure your needs and preference are met?

Help ▶ Save Submit

1. As a transmission customer, what's most important to you to ensure your needs and preference are met?

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Q3 - Hydro One Performance

Agenda Topic: Questions - Section 1

Instructions:

Please refer to slides 4-7.

Answer the question below and click Submit, then click Q4 to proceed.

Help ▶ Save Submit

1. As a transmission customer, overall, how satisfied are you with Hydro One's performance?

(5) Very satisfied
(4) Somewhat satisfied
(3) Neither satisfied nor dissatisfied
(2) Somewhat dissatisfied
(1) Very dissatisfied

Section 1 - Question 4

Q4 - Customer Challenges and Concerns

Agenda Topic: Questions - Section 1

Instructions:

Please refer to slides 4-7.

Enter your thoughts into the text box below, then click Submit, then proceed to Q5.

Thinking about your electricity needs as a transmission customer, what are the main challenges you face in your organization and industry today?

Help ▸ Save Submit

1. Thinking about your electricity needs as a transmission customer, what are the main challenges you face in your organization and industry today?

Section 1 - Question 5

Q5 - Concerns Ranking Exercise

Agenda Topic: Questions - Section 1

Instructions:

Please refer to slides 4-7.

Using your mouse or trackpad, drag and drop the following concerns into order.

#1 is the Greatest concern

#10 is the Lowest concern

Click Submit to finalize your order of preference, then proceed to Q6.

Help ▸ View Results Save Submit

1. Please rank for us in order how concerned your organization is (or would be) about the following regarding Hydro One:
    1. Hydro One's business relationship with you
    2. An increase in transmission rates - less than 5%
    3. An increase in transmission rates - more than 5%
    4. Adequate asset maintenance and replacement
    5. The number of unplanned interruptions
    6. The number of planned or scheduled interruptions
    7. Power quality
    8. Getting assurance that an increase in rates will improve reliability
    9. Hydro One asks for my organization's input while developing their investment plan
    10. The input I provide is reflected in Hydro One's investment plan

Q6 - Agree / Disagree - Proactivity

Agenda Topic: Questions - Section 1

Instructions:

Please refer to slides 4-7.

Answer the following question and click SUBMIT to finalize your response. The click Q7 to proceed.

Help

Save Submit

1. To what extent do you agree that Hydro One needs to be more proactive in addressing current and emerging reliability risks now, rather than deferring investments.

(5) Strongly agree
(4) Somewhat agree
(3) Neither agree nor disagree
(2) Somewhat disagree
(1) Strong disagree

Q7 - Review of System Performance

Agenda Topic: Questions - Section 2

Instructions:

Please refer to slides 9-16

Is there anything unclear about what has just been presented?

Once you click submit, proceed to Q8.

Help

Save Submit

1. Is there anything unclear about what has just been presented?

Section 2 - Question 8

Q8 - Interruption Awareness Question

Agenda Topic: Questions - Section 2

Instructions:

Please refer to slides 9-16

Are you aware of how many unplanned interruptions your organization experienced in 2015? Please tell us the number of interruptions.

Click Submit, then click Q9 to proceed.

Help

Save Submit

1. Are you aware of how many unplanned interruptions your organization experienced in 2015? Please tell us the number of interruptions.

(5) 1-5
(4) 6-10
(3) 11-15
(2) 16 or more
(1) I'm not sure

Section 2 - Question 9

Q9 - Reliability Performance vs. Risk

Agenda Topic: Questions - Section 2

Instructions:

Please refer to slides 9-16

As you heard...

Reliability performance refers to a measure of the ability of the transmission system to supply customers' electric power and energy requirements. It is calculated based upon the duration and frequency of interruptions at prescribed delivery points

Reliability risk refers to a relative measure of the possibility that the transmission system will not supply customers' electric power and energy requirements, at all time, due to planned and unplanned outages of system components.

Click Submit to finalize your answer, then click Q10 to proceed.

Help ▸ Save Submit

1. Do you feel you have a good understanding of the difference between reliability performance and reliability risk? ○ Yes ○ No

Q10 - Concerns About System Reliability Risk

Agenda Topic: Questions - Section 2

Instructions:

Please refer to slides 9-16

Answer the question below and click SUBMIT to finalize your response. Then proceed to Q11.

Help ▸ Save Submit

1. How concerned are you about system reliability risk? ▾

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Q11 - Scenario Input

Agenda Topic: Questions - Section 3

Instructions:

Please refer to the scenario slides for each of the corresponding questions below.

Scenario One: Slide 20

Scenario Two: Slide 21

Scenario Three: Slide 21

For an overview of the three potential scenarios please refer to slide 23.

Click Submit to finalize your answers, then proceed to Q12.

Help

Save Submit

1. Please enter your thoughts on Scenario One

2. Please enter your thoughts on Scenario Two

3. Please enter your thoughts on Scenario Three

Section 3 - Question 12

Q12 - Reliability vs. Rates

Agenda Topic: Questions - Section 3

Instructions:

What is the benefit of a reliable electricity system vs. the benefits of maintaining current rates?

Click Submit to finalize your response, then proceed to Q13.

Help ▶ Save Submit

1. What is the benefit of a reliable electricity system vs. the benefits of maintaining current rates?

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Q13 - Organization Risk Management

Agenda Topic: Questions - Section 3

Instructions:

Please answer each of the questions below, then click Submit to finalize your responses. Then proceed to Q14.

Help

Save Submit

1. Given what you've heard today, do you accept that an improvement in reliability risk comes at a cost?	Yes	No
2. Will you accept a rate increase for a transmission system plan where reliability risk still increases?	Yes	No
3. Will you accept a rate increase for a transmission system plan where reliability risk is unchanged?	Yes	No
4. Will you accept a rate increase for a transmission system plan where reliability risk improves?	Yes	No

5. If you could create the ideal aggregate / composite Scenario using elements of all three, what would it be? Please take as much time as you need to tell us in detail about these elements.

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EB-2016-0160
Exhibit B1-2-2
Attachment 3

Section 3 - Question 14

Q14 - Hydro One Proactivity

Agenda Topic: Questions - Section 3

Instructions:

Answer the following question and click Submit to finalize your response. Then proceed to Q15.

Help

Save Submit

1. To what extent do you agree that Hydro One needs to be more proactive in addressing emerging reliability risks now, rather than deferring investments.

(5) Strongly agree
(4) Somewhat agree
(3) Neither agree or disagree
(2) Somewhat disagree
(1) Strongly disagree

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Stakeholder Engagement Evaluation - Question 15

Q15 - Stakeholder Engagement

Agenda Topic: Stakeholder Engagement Process

Instructions:

This is the final screen. Please answer all questions below and click Submit.

Once you are done you can close the browser to exit. Thank you for your participation.

Help

Save Submit

1. I feel my feedback was heard today regarding Hydro One's approach to investment planning.

(5) Strongly agree
(4) Somewhat agree
(3) Neither agree nor disagree
(2) Somewhat disagree
(1) Strongly disagree

2. Would you be willing to participate in a similar discussion in the future?

3. How often do you think Hydro One should hold these sessions?

IDENTIFYING SYSTEM NEEDS: REGIONAL PLANNING PROCESS

1. INTRODUCTION

Planning transmission infrastructure in a regional context helps promote the cost effective development of the electricity infrastructure in Ontario. This is one of the key guiding principles in the Board's Renewed Regulatory Framework requirements which states that infrastructure planning on a regional basis, between licensed transmitters and distributors, is to be undertaken to ensure that regional issues and requirements are integrated into the utility's planning processes.

In Hydro One's previous rate application (EB-2014-0140), Hydro One documented a framework for implementing and transitioning to the new regional planning process outlined in the "The Process for Regional Infrastructure Planning in Ontario" report endorsed by the Board on May 17, 2013 and the subsequent Board amendments to the Transmission System Code and Distribution System Code in August 2013. Hydro One is actively involved in the development of regional infrastructure plans. This is consistent with Hydro One's business objectives of being responsive to customer needs and public policy and being a vital partner in the continued economic success of the province.

The following sections outline: (a) the regional planning process established in the Board endorsed report; (b) the customer consultation process to engage distributors and other customer groups in the regional planning activities; and (c) a status update on each of the regions, highlighting investments arising from regional planning that form part of Hydro One's investment plans, as outlined in Exhibit B1, Tab 3, Schedule 3.

2. THE REGIONAL PLANNING PROCESS

Planning for the electricity system in Ontario is done at essentially three levels:

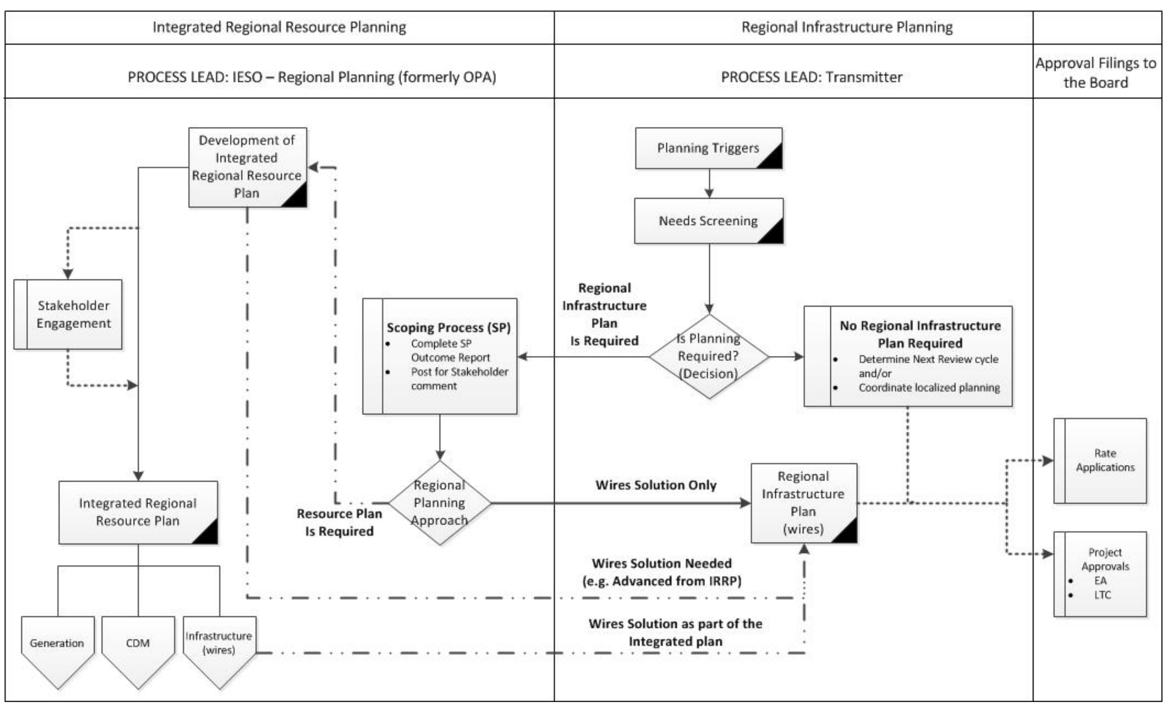
(1) bulk system;

(2) regional system; and

(3) distribution system.

Regional planning addresses issues at a localized level, such as the supply facilities that connect and deliver power to a group of load stations in an area or region. Figure 1 illustrates the various phases of the regional planning process and the trigger, process lead, and outcome for each respective phase. It is intended that this process be repeated for each region every five years. The process may be more frequent, depending upon the emergence of new needs.

Figure 1: Regional Planning Process



In general, the process consists of the following phases:

- Needs Screening (or Needs Assessment);
- Scoping Process (or Scoping Assessment);
- Integrated Regional Resource Plan ("IRRP"); and
- Regional Infrastructure Plan ("RIP").

The regional planning process begins with planning triggers. Triggers include a regularly scheduled Needs Assessment by the transmitter, a scheduled review specified in an existing RIP, a Government directive, a significant change to codes and standards, or an emergent need brought forward by the transmitter, distributors, customers, or the Independent Electricity System Operator ("IESO") that cannot wait until the next scheduled review.

The initial phase of the regional planning process is the Needs Assessment phase which is led by the transmitter. In this phase, needs are identified in consultation with distributors and the IESO, and a high level assessment is undertaken to determine potential alternatives or solutions to address the needs. In cases where: (a) the needs are local in nature; (b) further review by subsequent phases in the regional planning process is not required; and (c) the needs can be addressed directly by the transmitter and distributor(s) or other transmission connected customer(s) through transmission and/or distribution facilities ("wires") solution(s), then a local plan is developed. The local plan(s) ultimately becomes part of the RIP for the region.

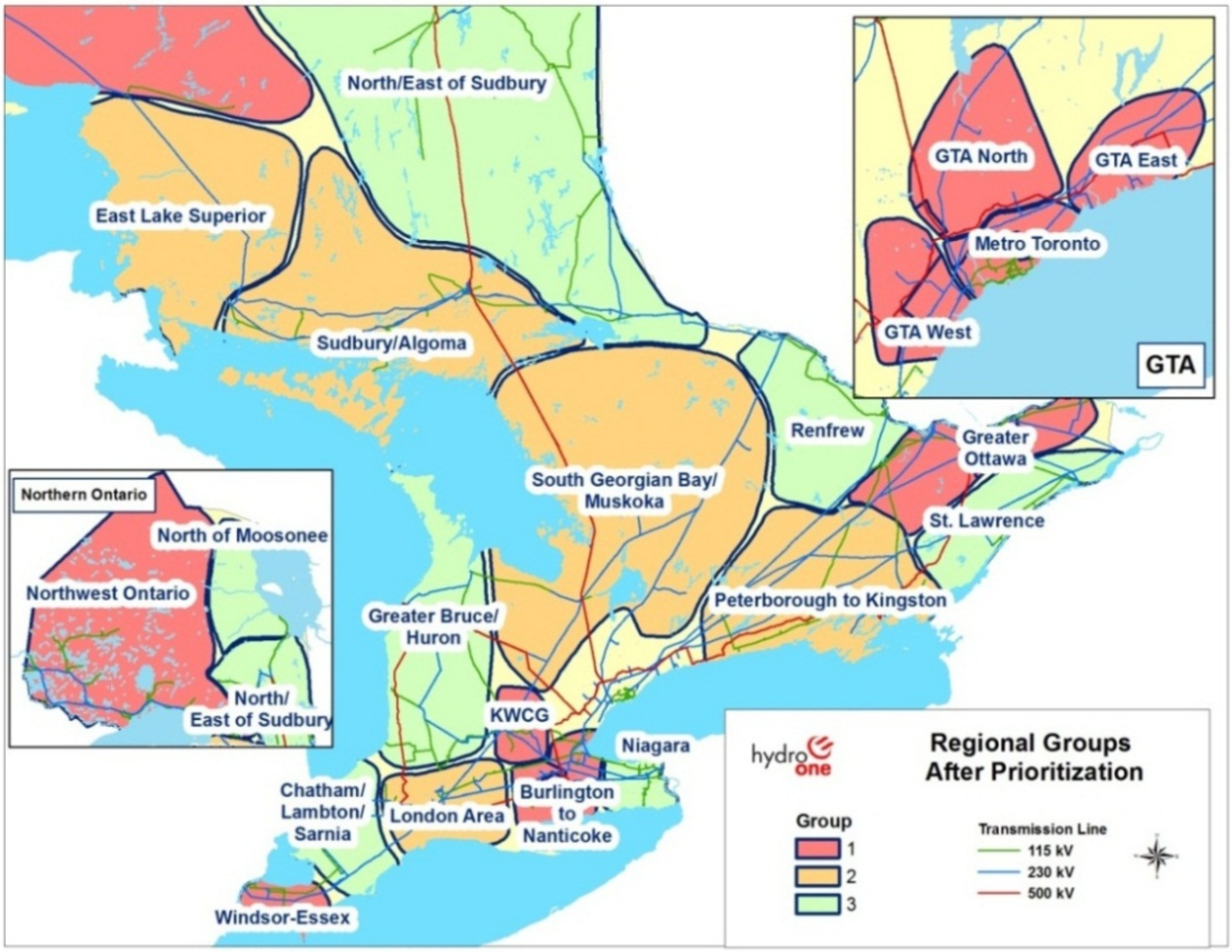
In other cases where further planning studies and coordination are considered necessary, the IESO initiates the Scoping Assessment phase. The IESO, in collaboration with the transmitter and impacted distributors, reviews the information collected during the Needs Assessment phase. The IESO also considers information relating to potential non-wires alternatives, and determines the most appropriate regional planning approach; i.e., whether an IRRP or a RIP or both, are required to address the needs in the region or sub-region.

The IRRP process involves the identification, evaluation and integration of potential wires and non-wires solutions at the regional or sub-regional level. The IRRP phase generally assesses resource versus wires infrastructure options at a higher level, but with sufficient detail to allow for a comparison of options. If the IRRP determines that resource options are best suited to meet a need, then those options are further planned by the IESO. However, if wires options are the more appropriate alternative, then those options are further assessed as part of the RIP process.

The RIP process is the final phase of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs. This phase is led and coordinated by the transmitter, and the deliverable of this phase is a comprehensive report of a wires plan for the region.

To undertake the regional planning process, the province has been divided into 21 electrical regions for the purposes of conducting assessments and developing regional plans. Each of these 21 regions have been assigned to one of the three regional planning groups in order to prioritize and manage the regional planning process, as noted in Figure 2 below. Hydro One Transmission is the lead transmitter in all regions, except East Lake Superior and North of Moosonee.

Figure 2: Regional Planning Groups



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	1. East Lake Superior (2)	1. Chatham/Lambton/Sarnia
2. Greater Ottawa	2. London Area	2. Greater Bruce/Huron
3. GTA East	3. Peterborough to Kingston	3. Niagara
4. GTA North	4. South Georgian Bay/Muskoka	4. North of Moosonee (2)
5. GTA West	5. Sudbury/Algoma	5. North/East of Sudbury
6. KWCG (1)		6. Renfrew
7. Metro Toronto		7. St. Lawrence
8. Northwest Ontario		
9. Windsor-Essex		

Note: *(1) "KWCG" stands for Kitchener-Waterloo-Cambridge-Guelph*
(2) Hydro One is not the lead transmitter in this region

3. REGIONAL PLANNING CUSTOMER CONSULTATION PROCESS

As part of the regional planning process, Hydro One undertakes extensive consultation with the local distributing companies ("LDCs") and the IESO to identify needs and develop plans as envisioned by the Board in its Renewed Regulatory Framework. Hydro One also reaches out to its large transmission connected customers to obtain and update their future plans and electricity load forecasts.

Over the last two years, working groups made up of the IESO, LDCs and Hydro One were established in all of the 19 regions across the province where Hydro One is the lead transmitter. More than 70 distributors along with the IESO have participated in the regional planning process. Inputs from other transmission connected customers were also obtained where available. In the Northwest Ontario region, the working group was expanded to include other stakeholder groups such as: Northwestern Ontario Municipal Association, Common Voice, Ontario Mining Association and municipalities. This unique approach was required due to the vast geographic area, uncertainties, and challenges not normally seen in other parts of the province. For example, the majority of the forecasted load growth in northwestern Ontario is driven by potentially large incremental load from connected industrial customers such as mines and forestry. This region also includes communities not connected to the provincial transmission grid.

At each phase of the regional planning process a combination of the following consultation actions are undertaken for each of the regions to ensure the involvement and engagement of the working group members:

1. **Pre-meeting Conference Calls / Webinars:** At the beginning of each phase, LDCs and the IESO are notified in advance of upcoming regional planning activities and are provided an overview of the process.

2. **Kick-Off Meetings / Conference Calls / Webinars:** Kick-off meetings with the working group are organized to initiate each of the phases of the regional planning process and provide templates for the collection of information/data.
3. **Additional Face to Face Meetings / Conference Calls / Webinars:** The working group meets on a regular basis to discuss planning matters such as assessment methodology, customer needs, and regional needs and timing before recommending a preferred solution.

In addition to the distributors who are part of the working group, other customers and stakeholders, such as those involved in Local Advisory Committees, are also engaged in the regional planning process and have an opportunity to provide input as part of the IESO led engagement during the IRRP phase.

A broader engagement with the public and other stakeholders also occurs at the project development level. Major projects go through the process of Environmental Assessment in accordance with the Ontario *Environmental Assessment Act* and/or Leave to Construct in accordance with Section 92 of the *Ontario Energy Board Act*. Both of these processes require extensive public and stakeholder consultation on projects which occurs through meetings, presentations, public information centres, and newspaper advertisements, etc.

In addition to the published reports and other relevant information on Hydro One's website, these consultations ensure transparency of regional activities that may influence stakeholders' future planning strategies, and demonstrate Hydro One's responsiveness to public policy and commitment to being a vital partner in the continued economic success of the province. For specific details at the regional level on the participants involved in the planning process please refer to the regional planning reports filed as Attachments to this exhibit or to the Hydro One's Regional Planning website.

http://www.hydroone.com/RegionalPlanning/Pages/home.aspx

4. STATUS OF REGIONAL PLANNING ACTIVITIES

As the lead transmitter, Hydro One Transmission leads the Needs Assessment and RIP phases of the regional planning process, and actively participates in the Scoping Assessment and IRRP phases led by the IESO.

Hydro One is required, as per Section 3C.3.3 of the Transmission System Code, to submit a report to the Board annually on the status of the regional planning activities for all regions. Hydro One filed its 2015 Status Report with the Board on November 2, 2015.[1]

Since filing the 2015 Status Report, Hydro One has continued to advance its regional planning activities. Table 1 below provides a summary of the status for each region and sub-region, showing the planning phases underway and completed. Subsequent sections provide a further description of the regional planning activities and investment recommendations for each of the regions and sub-regions for which Hydro One is the lead transmitter. A letter from the IESO on the overall IRRP status is presented in Attachment 1.

Hydro One is also required under Section 3C.2.2 of the Transmission System Code to provide Planning Status Letters to a licensed distributor or a licensed transmitter confirming the status of regional planning for a region suitable for the purpose of supporting an application proposed to be filed with the Board by the distributor or requesting transmitter. In addition to the Planning Status Letters outline in Appendix H of the 2015 Status Report, Hydro One has recently provided a Planning Status Letter to Newmarket-Tay Power Distribution Ltd.

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[1] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2011-0043/HONI_2015_Regional_Planning_Status_Report_20151102.pdf

Table 1: Regional Planning Status Summary

Group	Region	Sub-Region	NA	SA	IRRP	RIP
1	Burlington to Nanticoke	Brant				
		Bronte				
		Greater Hamilton				
		Caledonia-Norfolk				
	Greater Ottawa	Ottawa				
		Outer Ottawa				
	GTA East	Oshawa-Clarington				
		Pickering-Ajax-Whitby				
	GTA North	York				
		Western				
	GTA West	Northwestern				
		Southern				
	Kitchener-Waterloo-Cambridge-Guelph (KWCG)					
	Metro Toronto	Central Downtown				
		Northern				
	Northwest Ontario	North of Dryden				
		Greenstone-Marathon				
		City of Thunder Bay				
		West of Thunder Bay				
		Remote Communities				
	Windsor-Essex					
2	East Lake Superior*		Status to be provided by the lead transmitter			
	London Area	Greater London				
		Alymer-Tillsonburg				
		Strathroy				
		Woodstock				
		St. Thomas				
	Peterborough to Kingston					
	South Georgian Bay/Muskoka	Barrie/Innisfil				
		Parry Sound/Muskoka				
	Sudbury/Algoma					
3	North of Moosonee*		Status to be provided by the lead transmitter			
	Chatham/Lambton/Sarnia					
	Greater Bruce/Huron					
	Niagara					
	North/East of Sudbury					
	Renfrew					
	St. Lawrence					

In Progress | Completed or Deemed Completed | Not Required | Has Not Started

Note: *The asterisk (*) represents regions/sub-regions Hydro One is not the lead transmitter.*

4.1 Regions in Group 1

There are nine regions identified in Group 1. Specific details on the status of the regional planning process and the investments arising from regional planning that form part of Hydro One's investment plans have been highlighted below.

Burlington to Nanticoke

Burlington to Nanticoke Region comprises of four sub-regions: **Brant**, **Bronte**, **Greater Hamilton**, and **Caledonia-Norfolk.** The IRRP has been completed for Brant sub-region, and is currently in-progress for Bronte sub-region. The Brant IRRP report is presented in Attachment 2 to this exhibit. The region's RIP will be initiated after the IRRP is completed.

The needs in the other two sub-regions were local in nature, and are part of the local plan developed by Hydro One and the impacted LDCs.

Consistent with the Brant IRRP recommendations, this rate application includes transmission infrastructure investments associated with installing 115 kV switching facilities at Brant TS (Project D09).

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/Burlington/Pages/home.aspx

Greater Ottawa

Greater Ottawa Region comprises of two sub-regions: **Ottawa Area** and **Outer Ottawa**. The RIP for this region has been completed, and is presented in Attachment 3 to this exhibit.

Consistent with the Greater Ottawa RIP recommendations, this rate application includes a number of investments such as: replacement/upgrade of transformers at Hawthorne TS (Project D08 and S34), Lisgar TS (Project D16), and Overbrook TS, as well as the reconfiguration of the 115kV circuit between Riverdale Junction and Overbrook TS (Project D10).

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/Ottawa/Pages/default.aspx

GTA East

GTA East Region comprises of two sub-regions: **Pickering-Ajax-Whitby** and **Oshawa-Clarington**. The IRRP is currently in progress for the Pickering-Ajax-Whitby sub-region. The IRRP working group has reaffirmed the need for a new transformer station in the Seaton area by Veridian Connections Inc. The region's RIP will be initiated after the IRRP is completed.

The needs in the Oshawa-Clarington sub-region were local in nature and a local plan was developed by Hydro One and the impacted LDCs. The local plan recommended a new load station "Enfield TS" located at the new Clarington TS site to relieve Wilson TS and Thornton TS. In addition, a plan to manage the utilization of Thornton TS feeders is being developed by the impacted LDCs.

This rate application includes both the near-term transmission infrastructure investment identified by the IESO as part of the IRRP process related to connection of a new transformer station in the Pickering-Ajax-Whitby area "Seaton MTS" (Project D17), as well as the construction of a new load station "Enfield TS" (Project D21) identified in the local plan for the Oshawa-Clarington sub-region.

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/GTA_East/Pages/default.aspx

GTA North

GTA North Region comprises of two sub-regions: **York** and **Western**. The RIP for this region has been completed, and is presented in Attachment 4 to this exhibit.

Consistent with the GTA North RIP recommendations, this rate application includes transmission infrastructure investments associated with the installation of breakers and switches at Holland TS in York Region (Project D07), the installation of two inline switches at Grainger Junction on the 230kV circuits V71P/V75P, and the connection of a new load station "Vaughan #4 MTS".

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/GTANorth/Pages/default.aspx

GTA West

GTA West Region comprises of two sub-regions: **Northwestern** and **Southern**. The RIP for this region has been completed and is presented in Attachment 5 to this exhibit.

Consistent with the GTA West RIP recommendations, this rate application includes the connection to a new load station "Halton TS#2".

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/GTAWest/Pages/default.aspx

Kitchener-Waterloo-Cambridge-Guelph ("KWCG")

The RIP for the KWCG Region was completed and is presented in Attachment 6 to this exhibit.

Consistent with the KWCG RIP recommendations, this rate application includes the investment associated with the installation of in-line switches on the 230kV circuits M20D/M21D at Galt Junction (Project D06).

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/KWCG/Pages/default.aspx

Metro Toronto

Metro Toronto Region comprises of two sub-regions: **Central Downtown** and **Northern**. The RIP for this region has been completed and is presented in Attachment 7 to this exhibit.

Consistent with the Metro Toronto RIP recommendations, this rate application includes transmission infrastructure investments such as the expansion of Runnymede TS with the construction of a new transformer station and reconductoring the 115 kV circuits (Project D19), the expansion of Horner TS via the construction of a second transformer station

(Project D15), the upgrade of the Richview x Manby corridor – the Southwest GTA transmission reinforcement project (Project D11), and the Manby TS autotransformer overload protection scheme.

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/Toronto/Pages/default.aspx

Northwest Ontario

Northwest Ontario Region comprises of several sub-regions: **North of Dryden, Greenstone-Marathon, City of Thunder Bay, West of Thunder Bay,** and **Remote Communities**. The IRRP for the North of Dryden sub-region has been completed and is presented in Attachment 8 to this exhibit. The IRRP for another three sub-regions are currently in progress. The region's RIP will be initiated after all of the sub-regional IRRPs are completed.

Consistent with the North of Dryden IRRP recommendations, this rate application includes transmission infrastructure investments associated with upgrading sections of 115 kV circuit E4D (Project D13).

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/NWOntario/Pages/default.aspx

Windsor-Essex

The RIP for Windsor-Essex Region was completed and is presented in Attachment 9 to this exhibit.

Consistent with the Windsor-Essex RIP recommendations, this rate application includes transmission infrastructure investments associated with Supply to Essex County Transmission Reinforcement (Project D14), reconfiguration of Keith TS due to the Gordie Howe International Bridge Project (Project S81), as well as replacement of transformers at Kingsville TS.

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/Windsor-Essex/Pages/default.aspx

4.2 Regions in Group 2

There are five regions identified in Group 2. Specific details on the status of the regional planning process and the investments arising from regional planning that form part of Hydro One's investment plans have been highlighted below.

London Area

The London Area Region comprises of five sub-regions: **Greater London, Aylmer-Tillsonburg, Strathroy, Woodstock,** and **St. Thomas**. The IRRP is currently in progress for the **Greater London** sub-region.

Hydro One is also initiating a wires planning study to address supply capability limitation in the **Aylmer-Tillsonburg** sub-region while the Greater London IRRP is still underway. Recommendations from this study will ultimately become part of the London Area RIP. The region's RIP will be initiated after the IRRP is completed.

The needs in the other sub-regions were local in nature. Local plans are in the process of being developed by Hydro One and the impacted LDCs to address these needs.

Planning studies are still underway and specific investments have not been identified in this rate application.

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/LondonArea/Pages/default.aspx

Peterborough to Kingston

The Needs Assessment for the **Peterborough to Kingston** Region has been completed, and determined that the needs were local in nature. The Needs Assessment Report is presented in Attachment 10 to this exhibit.

A local plan has been developed by Hydro One and the impacted LDCs to balance the Gardiner TS load. In addition, IESO will assess and develop a plan for contingencies associated with the 115 kV circuit Q6S and 230 kV circuit P15C as part of its bulk system planning study led by the IESO.

Planning studies are still underway and specific investments have not been identified in this rate application.

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/Peterborough/Pages/default.aspx.

South Georgian Bay/Muskoka

South Georgian Bay/Muskoka Region comprises of two sub-regions: **Barrie/Innisfil** and **Parry Sound/Muskoka**. The IRRPs are currently in progress for each sub-region. The region's RIP will be initiated after the IRRPs are completed.

In the interim, at the recommendation of IRRP working group, the IESO has issued a letter to Hydro One to develop wires options and proceed with a preferred alternative to address the equipment approaching its end-of-life at Barrie TS, as presented in Attachment 11 to this exhibit.

Consistent with the IESO letter, this rate application includes transmission infrastructure investments in this region associated with the asset condition issues and upgrade of Barrie TS and 115kV circuits E3B/E4B to 230 kV (Project D12).

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Pages/default.aspx

Sudbury/Algoma

The Needs Assessment for the **Sudbury/Algoma** Region has been completed and determined that the needs were local in nature. The Needs Assessment Report is presented in Attachment 12 to this exhibit.

A local plan has been developed by Hydro One and the impacted LDCs to address low voltage regulation issues at Manitoulin TS. Further assessments have indicated that Manitoulin TS transformers are capable of maintaining acceptable voltage level, thus no further action is required.

Consistent with the findings in the Needs Assessment report, this rate application includes transmission infrastructure investments associated with the construction of a new 230/44kV transformer station at Hanmer TS to replace the existing 115/22kV Coniston TS (Project D18).

Further details are available on Hydro One's Regional Planning website:
http://www.hydroone.com/RegionalPlanning/Sudbury-Algoma/Pages/default.aspx.

East Lake Superior

Great Lakes Power Transmission LP ("GLP") is leading the regional planning efforts as the lead transmitter for this region. A Needs Assessment was conducted for the East Lake Superior region in late 2014 by a working group led by GLP, and including representatives from the IESO, Hydro One Transmission, Algoma Power Inc., PUC Distribution and Chapleau Public Utility Corporation. Through this process, there were three potential needs identified. It was determined that the needs were local in nature and local plans will be developed by GLP and the impacted LDCs. This rate application does not include any transmission infrastructure investments in this region.

4.3 Regions in Group 3

There are seven regions identified in Group 3 in which the regional planning process is currently underway. Hydro One is the lead transmitter for all regions with the exception of North of Moosonee. Needs Assessments have been completed for two regions (North/East of Sudbury and Renfrew) and the assessments for the other regions are expected to be completed in the second quarter of 2016. This rate application does not include any transmission infrastructure investments in these regions.

North/East of Sudbury

The Needs Assessment for the **North/East of Sudbury** Region has been completed and is presented in Attachment 13 to this exhibit. The needs identified in this region were local in nature. Local plans will be developed by Hydro One and the impacted LDCs in the area to address Timmins TS/Kirkland Lake TS voltage regulation issues.

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/NE-Sudbury/Pages/default.aspx

Renfrew

The Needs Assessment for the **Renfrew** Region has been completed and is presented in Attachment 14 to this exhibit. The report determined that there were no capacity, system reliability and operating needs that require investments over the planning horizon.

Further details are available on Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/Renfrew/Pages/default.aspx.

5. REGIONAL PLANNING REPORTS

Attachment 1: Letter from IESO on Status of Integrated Regional Resource Plans

Attachment 2: Integrated Regional Resource Plan - Brant Sub-Region

Attachment 3: Regional Infrastructure Plan – Greater Ottawa

Attachment 4: Regional Infrastructure Plan – GTA North

Attachment 5: Regional Infrastructure Plan – GTA West

Attachment 6: Regional Infrastructure Plan – KWCG

Attachment 7: Regional Infrastructure Plan – Metro Toronto

Attachment 8: Integrated Regional Resource Plan – North of Dryden Sub-Region

Attachment 9: Regional Infrastructure Plan – Windsor-Essex

Attachment 10: Needs Assessment Report – Peterborough to Kingston

Attachment 11: Letter from IESO Initiating Near-Term Transmission Project identified through the Barrie/Innisfil Integrated Regional Resource Planning

Attachment 12: Needs Assessment Report – Sudbury/Algoma

Attachment 13: Needs Assessment Report – North/East of Sudbury

Attachment 14: Needs Assessment Report – Renfrew

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

April 25, 2016

Mr. Bing Young
Director, System Planning
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2P5

Dear Mr. Young:

Re: Regional Planning Progress Update

The purpose of this letter is to provide a progress update to Hydro One on the regional planning areas where planning is underway, but a Regional Infrastructure Plan has not yet been completed. This update covers regional planning processes that are currently in the needs assessment, Scoping Assessment ("SA") or the Integrated Regional Resource Planning ("IRRP") phase. This regional planning progress update is intended to be submitted with Hydro One's transmission rate applications in accordance with Section 2.4.2 of the Ontario Energy Board's Chapter 2 Filing Requirements For Electricity Transmission Applications, which states:

> *Where regional planning is underway, but a Regional Infrastructure Plan has not yet been completed for the applicable region, the applicant shall submit a letter from the Independent Electricity System Operator ("IESO"), identifying the status of the regional planning process, and the potential impacts on the applicant's investment plans.*

Eight IRRPs for Group 1 regions have been completed and posted to date:

Table 1: Group 1 Completed and Posted IRRPs

Group	Region	Sub-Region
1	Burlington to Nanticoke	Brant
	Greater Ottawa	Ottawa
	GTA North	York
	GTA West	Northwestern
	Kitchener-Waterloo-Cambridge-Guelph (KWCG)	N/A
	Metro Toronto	Central Downtown
	Northwest Ontario	North of Dryden
		Greenstone-Marathon[1]
	Windsor-Essex	N/A

[1] On June 22, 2015, the IESO posted an interim report for the Greenstone-Marathon sub-region and that provides recommendations to address the near-term elements identified within the IRRP. The purpose of the interim report is to facilitate critical decision making for customers considering new connections in the Greenstone-Marathon area. A comprehensive 20-year IRRP report will be produced in the second quarter of 2016.

Currently there is no SA underway for Groups 1B and 2 IRRPs. Below are eight sub-regional IRRPs in progress which are being led by the IESO:

Table 2: Groups 1B and 2 IRRPs in Progress

Group	Region	Sub-Region	Planned Posting Date
1B	GTA East	Pickering-Ajax-Whitby	Q2 2016
	Northwest Ontario	Greenstone-Marathon	Q2 2016
		Thunder Bay	Q3 2016
		West of Thunder Bay	Q3 2016
	Burlington to Nanticoke	Bronte	Q3 2016
2	South Georgian Bay/Muskoka	Barrie/Innisfil	Q4 2016
		Parry Sound/Muskoka	Q4 2016
	London Area	Greater London	Q1 2017

These IRRPs (Groups 1B and 2) are expected to be posted in the second to fourth quarters of 2016 and the first quarter of 2017. Once the IRRPs have been completed, Hydro One, as the lead transmitter, will initiate the Regional Infrastructure Planning ("RIP") phase as the final step in the regional planning process for regions or sub-regions where transmission is an identified option.

For two of the eight IRRPs currently underway in Groups 1B and 2, the IESO has identified two near-term needs (present – 5 years) that are best addressed by transmission options. Due to the lead time required, the IESO has recommended that Hydro One initiate the transmission planning and project development to meet these needs ahead of the completion of the IRRP. In the IRRP for the South Georgian Bay/Muskoka Region, the need to address the transmission supply capability to the Barrie area was identified; and in the GTA East Region, a need to provide the 230 kV transmission supply for a new transformer station in the Pickering-Ajax-Whitby area was identified.

For Group 3 IRRPs in progress, needs assessments are still underway to determine if further action is required. Below is the current status for Group 3 regions:

Table 3: Group 3 regions

Group	Region	Status
3	Chatham-Kent/Lambton/Sarnia	Needs assessments in progress
	Greater Bruce/Huron	
	Niagara	
	North of Moosonee[2]	
	North/East of Sudbury	
	St. Lawrence	
	Renfrew	Coordinated regional planning not required

[2] Five Nations Energy Inc. ("FNEI") is the lead transmitter for the North of Moosonee region

For all of the above regions where an IRRP has not yet been completed, needs are continuing to be refined and both resource and "wires" options are still being assessed. Until these IRRPs are completed, the IESO does not have further information to share on potential transmission investments and their impact on the applicant's investment plans.

Yours truly,

Nancy Marconi

Nancy Marconi
Senior Manager, Regulatory Affairs
Independent Electricity System Operator

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EB-2016-0160
Exhibit: B1-2-3
Attachment 2
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BRANT AREA
INTEGRATED REGIONAL RESOURCE PLAN

Part of the Burlington-Nanticoke Planning Region | April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Brant Area

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Brant Area Working Group, which included the following members:

- Independent Electricity System Operator
- Brant County Power Inc.
- Brantford Power Inc.
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Brant Area Working Group assessed the adequacy of electricity supply to customers in the Brant Area over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Brant Area; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Brant Area Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Brant Area Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
C&S	Codes and Standards
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CHP	Combined Heat and Power
CHPSOP	Combined Heat and Power Standard Offer Program
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
EA	Environmental Assessment
EM&V	Evaluation, Measurement and Verification
EV	Electric Vehicle
FIT	Feed-in Tariff
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
LMC	Load Meeting Capability
MCOD	Maximum Commercial Operation Date
MW	Megawatt
MEP	Municipal Energy Plan
MEP/CEP	Municipal or Community Energy Planning
MTS	Municipal Transformer Station
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority

Abbreviation	Description
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	(Ontario's) Provincial Policy Statement
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SCGT	Simple-Cycle Gas Turbine
SPS	Special Protection System
TOU	Time-of-Use
TS	Transformer Station
Working Group	Technical Working Group for Brant Area IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Brant Area ("Area") over the next 20 years from 2014 to 2033. This report was prepared by the IESO on behalf of a Technical Working Group composed of the IESO, Brant County Power Inc., Brantford Power Inc., Hydro One Distribution, and Hydro One Transmission ("the Working Group").

The Brant Area encompasses the County of Brant, City of Brantford and surrounding areas. It has an estimated population of over 136,000 people. The electricity demand mix is comprised of residential, commercial and industrial uses. The Brant Area is supplied by the Brant TS, Powerline MTS and Brantford TS.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the twenty-one electricity planning regions at least once every five years.

Under the Province's Growth Plan for the Greater Golden Horseshoe,[1] the Brant Area is expected to experience continued population growth in the coming decades. It continues to attract industrial and commercial customers and create opportunities for future development. This IRRP will help to ensure that the electricity system will support the expected development over the long term.

The Brant Area is a sub-region within the Burlington/Nanticoke region established through the OEB regional planning process. This report therefore contributes to fulfilling the requirements for the Burlington/Nanticoke region as mandated by the OEB. A second sub-region of the Burlington/Nanticoke region consists of the Bronte Area of Oakville and Burlington; this sub-region will be studied as a separate IRRP and is not included in the scope of this IRRP.

This IRRP for Brant identifies and coordinates options to meet electricity needs in the Area over the next 20 years ("study period") and is sub-divided into the near term (0-5 years, or 2014 through 2018), medium term (6-10 years, or 2019 through 2023) and longer term (11-20 years, or 2024 through 2033). Specifically, this IRRP identifies investments for immediate

[1] *Growth Plan for the Greater Golden Horseshoe, 2006 under the Places to Grow Act, 2005*

implementation to meet near- and medium-term needs in the Area, respecting expected lead times for development. This IRRP also identifies a number of options to meet longer-term needs, but given forecast uncertainty, the longer development lead time and the potential for technological change, the plan maintains flexibility for longer-term options and does not recommend specific projects at this time. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork to meet future needs, should they arise. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020, so that the results of these actions can inform a decision should one be needed at that time.

This report is organized as follows:

- A summary of the recommended plan for the Brant Area is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Brant Area and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation assumptions, are described in Section 5;
- Near- medium- and long-term electricity needs in the Brant Area are presented in Section 6;
- Options for meeting near- and medium-term needs are assessed and recommendations for the near-term plan are provided in Section 7;
- Alternatives for meeting long-term needs are discussed and actions to support development of the long-term plan are provided in Section 8;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Brant IRRP provides recommendations to address the Area's forecast electricity needs over the next 20 years, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). This IRRP identifies forecast electricity needs in the Area over near term (0-5 years, or 2014 through 2018), medium term (6-10 years, or 2019 through 2023) and longer term (11- 20 years, or 2024 through 2033). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost, feasibility, and maximization of the use of the existing electricity system, where it is economic to do so.

This IRRP identifies specific projects for implementation in the near and medium term. This is necessary to ensure that they are in-service in time to address the Area's more urgent needs, respecting the lead time for development of the recommended infrastructure.

This IRRP identifies a number of alternatives to prepare to meet the Area's longer-term electricity needs. However, as these needs are forecast to arise in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to recommend specific projects at this time. Instead, near-term actions are identified to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform a decision at that time.

2.1 Near-Term and Medium-Term Plan (2014 through 2023)

Near-Term Need
• Supply capacity in the Brant-Powerline 115 kV sub-system is inadequate today

The first element of the near-term plan is to account for targeted conservation and contracted distributed generation ("DG"). To address urgent supply capacity needs, two transmission projects are also recommended. The development of one of the transmission projects is currently underway; the former OPA issued a letter[2] to Hydro One Networks Inc.

[2]Letter to Hydro One:
http://www.hydroone.com/RegionalPlanning/Burlington/Documents/OPA Letter - Burlington Nanticoke - Brant.pdf

("Hydro One") supporting this near-term project in order to ensure it was initiated and brought into service in time to address an urgent need. The second transmission project is under discussion between Brantford Power Inc., Brant County Power Inc. and Hydro One. These projects are described below and their respective locations are shown in Figure 2-1. The estimated cost of these transmission projects is approximately $13-16 million. Together, these projects can increase the load meeting capability ("LMC") of the 115 kV sub-system from 104 MW to approximately 165 MW. Combined with the other near- and medium-term recommendations, these projects will be sufficient to meet the forecast demand growth until the end of the study period.

Figure 2-1: Brant Area Electricity System

These recommendations meet the near- and medium-term electricity needs of the Brant Area in a timely and cost-effective manner, and were developed with a view to maximizing the use of the existing system.

Recommended Actions

1. Implement conservation and distributed generation and monitor results

The implementation of provincial conservation and DG targets established in the 2013 Long Term Energy Plan ("LTEP") are key components of the near- and medium-term plan for the

Brant Area. In developing the demand forecast, peak-demand impacts associated with the provincial targets were assumed before identifying any residual needs, consistent with the provincial Conservation First policy.[3] Conservation resources account for approximately 40% of the forecast demand growth during the first 10 years of the study.

As the provincial conservation targets are energy[4] based, the IESO with the Area local distribution companies ("LDCs") will monitor the magnitude of the peak demand savings resulting from these targets in the Brant Area. This will be an important element of the near-term plan, and will also lay the foundation for the long-term plan by gauging actual performance of specific conservation measures, and assessing potential in the Area for further conservation efforts.

Provincial programs that encourage the development of distributed generation, such as the Feed-in-Tariff ("FIT"), microFIT, and Combined Heat and Power Standard Offer ("CHPSOP") programs, can also contribute to reducing peak demand in the Region, dependent , in part, on local interest and opportunities for development. Existing and committed distributed generation impacts were also assumed before identifying needs for the Area. It is expected that distributed generation resources will reduce the gross forecast for the Area by approximately 5 % for the study period. The LDCs and the IESO will continue their activities to support DG initiatives where appropriate and monitor their impacts.

2. Install capacitor banks at Powerline MTS

To meet the urgent need to provide capacity relief to the Area's 115 kV supply pocket the Working Group recommended the installation of 30 MVAR of capacitor banks at Powerline MTS. The estimated cost from Brantford Power and Brant County Power for this project is approximately $1-million. These capacitor banks are expected to be in-service for the summer of 2015, and will provide additional capacity of 21 MW to the Brant-Powerline sub-system. Implementation began in 2014 with the former OPA issuing a letter supporting this project so that it could be brought into service in time to address urgent needs.

[3] Conservation First policy:
http://www.energy.gov.on.ca/en/conservation-first/http:/www.energy.gov.on.ca/en/conservation-first/
[4] The provincial targets are for energy and have to be converted to capacity to calculate impact on peak demand by conservation.

3. Connect existing 115 kV Circuits B12/13 to B8W

To meet the remaining supply capacity need in the near term, the Working Group recommended the installation of three (3) 115 kV breakers to connect the existing circuits B12/13 from Hamilton to B8W from Woodstock. The budgetary estimate for this project is $12-15 million with an in-service date of 2017. These switching facilities are expected to provide additional capacity of 40 MW to the Brant-Powerline sub-system after the addition of the capacitor banks at Powerline MTS.

4. Demand response Pilot Program for Brant

A pilot demand response ("DR") program will be considered by the IESO in order to identify costs and determine feasibility and potential of DR to meet supply capacity needs in the Area. If DR proves to be feasible and economic, it could play an important role in long-term planning for the Area.

2.2 Near- and Medium-Term Actions in Support of Long-Term Plan (2024 through 2033)

The recommended near- and medium-term solutions are expected to satisfy the forecast demand growth for the expected-growth scenario until the end of the study period. In the long term, the Brant Area electricity system's ability to supply load will be constrained if additional industrial loads arise in the Area or higher demand growth occurs. Thus, the Working Group believes it is prudent to plan to meet a higher-demand scenario for the longer term. This will provide a capacity margin to supply emerging needs, and allow flexibility and time to plan for the next round of growth should a supply gap materialize.

A number of alternatives are possible to meet the Area's longer-term needs under in the high-demand growth scenario, including combinations of conservation, local generation, "wires" (transmission and distribution) and other emerging technologies. While specific solutions do not need to be committed today, it is prudent to begin work now in order to gather information, monitor developments, engage the community, and develop alternatives to meet the needs and to support decision-making in the next iteration of the IRRP. The longer-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. Long-term options will be reviewed in subsequent Burlington-Nanticoke regional planning studies.

Recommended Actions

1. Monitor load growth and conservation achievement and distributed generation performance

On an annual basis, the IESO will coordinate a review of conservation achievement, the uptake of provincial DG projects, and actual demand growth in the Brant Area. This information will be used to track the expected timing of longer-term needs to determine when a decision on the long-term plan is required. Information on conservation and DG performance will also provide useful feedback into the ongoing development of these options as potential long-term solutions. Additionally, the IESO will also monitor results and the incorporation of lessons learned from the DR pilot if it is implemented.

2. Undertake community engagement

Broad community and public engagement is essential to development of a long-term plan. As no long-term needs have been identified for the Brant Area, there is no requirement at this time for engagement on long-term options.

A Local Advisory Committee ("LAC") may be established for the broader Burlington to Nanticoke region once the IRRP process for the one remaining area in the Burlington to Nanticoke region has been completed. A LAC's purpose is to provide input and advice on regional plans and the engagement of those plans for an area or region. It is expected that a LAC will consist of community representatives and stakeholders. Advice from the LAC will be incorporated in developing engagement plans for the Area.

3. Continue ongoing work to develop transmission/generation options

The Working Group will continue to work together to evaluate the transmission and generation alternatives to meet the potential long-term needs.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term, and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA license changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

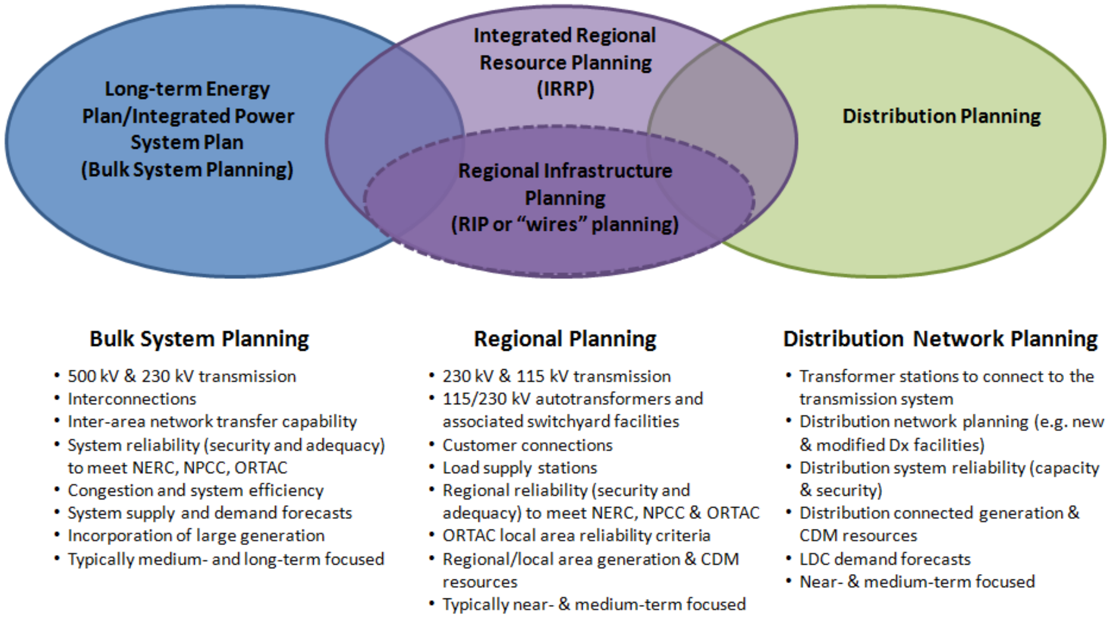
The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a scoping assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward "wires" solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required - and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites, and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Planning at the bulk system level typically considers the 230 kV and 500 kV network. It is typically carried out by the IESO and considers the major transmission facilities and assesses the resources needed to adequately supply the province. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

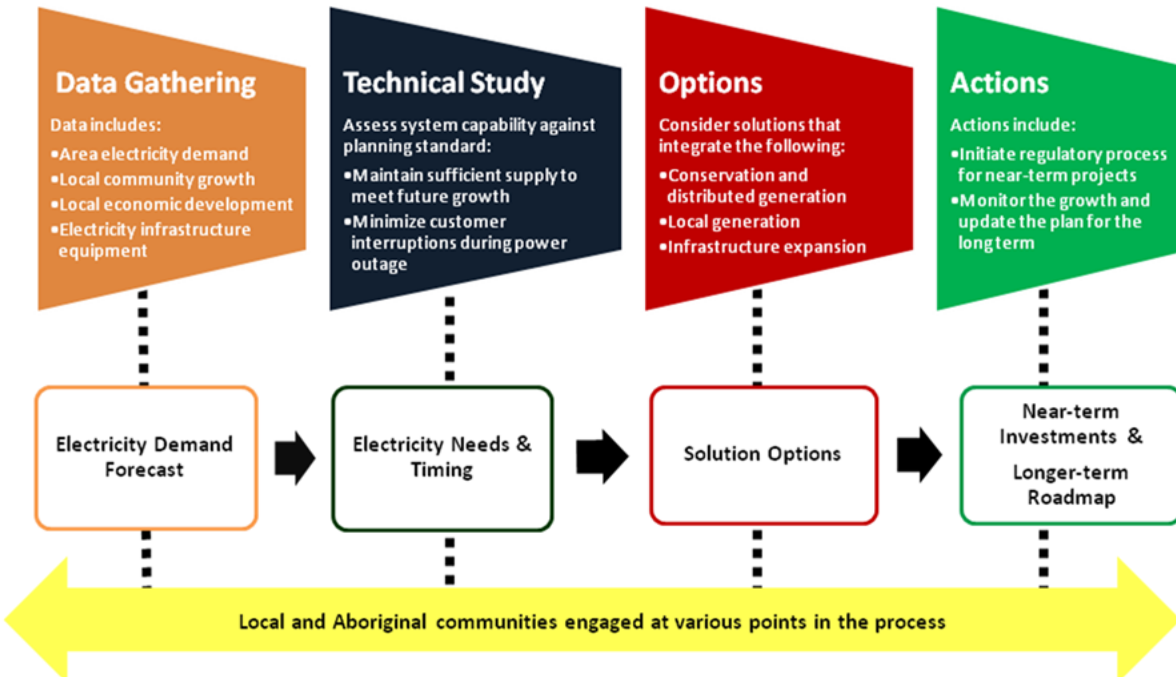
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nations and Métis communities and stakeholders. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Brant Area Working Group and IRRP Development

The Brant IRRP is a "transitional" IRRP in that it began prior to formalization of OEB's regional planning process and some of the study was conducted before the new process and its requirements were known. While much of the work completed in the early days of the study is consistent with the new process, certain aspects of the development of the IRRP have been refined, and the underlying data and assumptions, such as demand forecasts, have been updated to reflect changes since the study began.

In 2013, the Working Group was formed to assess the supply capacity for Brant Area. The Working Group developed a Terms of Reference for the study,[5] gathered data, identified near- to long-term needs in the Area, and recommended the near- and medium-term actions included in this IRRP.

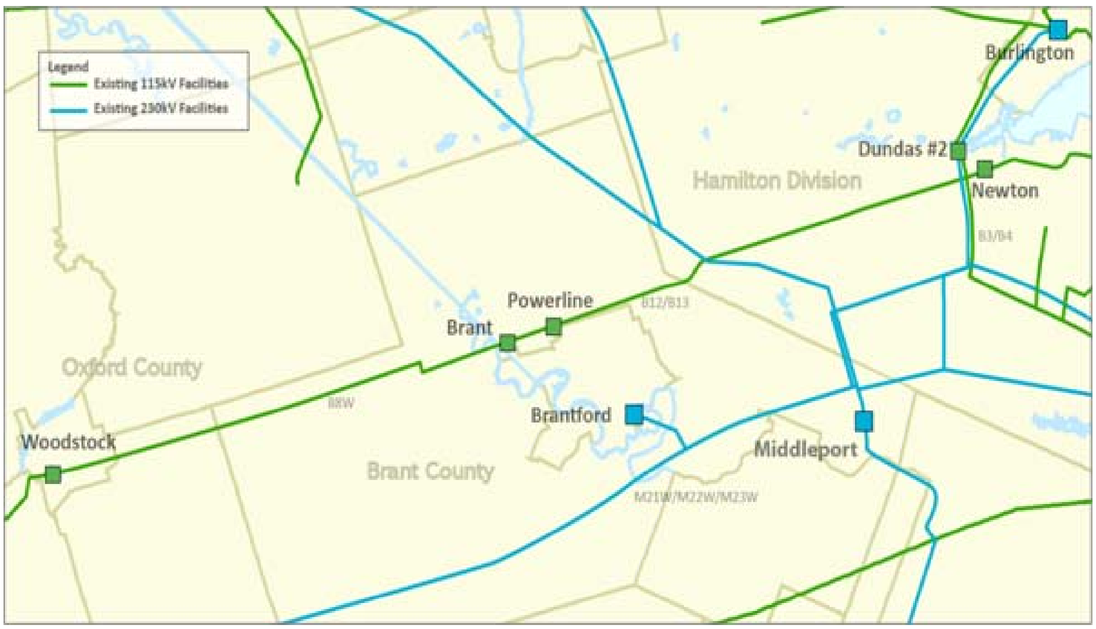
[5] Brant IRRP Terms of Reference:
http://powerauthority.on.ca/sites/default/files/planning/Brant-Terms-of-Reference.pdf

4. Background and Study Scope

This report presents an IRRP for the Brant Area over a 20-year period from 2014 to 2033. The Brant Area is a sub-region within the Burlington/Nanticoke region.

The geographic scope of the Brant IRRP includes the County of Brant and the City of Brantford. The electricity supply to the study Area is provided by three step-down stations: Brant TS, Powerline MTS and Brantford TS, as shown in Figure 4-1.

Figure 4-1: Brant Area and Vicinity



Brant TS and Powerline MTS are connected to the double-circuit 115 kV transmission line, B12/13[6] originating from Burlington TS. These stations are also backed up in emergencies by the 115 kV line B8W from Woodstock. Under normal operation, the B8W circuit is not connected to the Brant-Powerline sub-system circuits B12/13. The Brantford TS is supplied at 230 kV from the double-circuit transmission line M32/33W between Middleport TS (Hamilton) and Buchanan TS (London). The coincident peak demand of the three stations in summer 2014

[6] Circuits B12/13 also supply two other DESN stations, Dundas #2 TS and Newton TS in the Hamilton area serving customers of Horizon Utilities Corporation and Hydro One Distribution. As Dundas #2 TS and Newton TS are not directly impacted by the supply issues associated with the Brant Area in this study, a detailed assessment of these two stations is covered in the broader region needs screening of Burlington-Nanticoke.

was approximately 250 MW. Distribution service to customers in the Area is provided by Brant County Power Inc., Brantford Power Inc. and Hydro One Distribution.

For the purposes of this IRRP, the term "Brant Area" is used to more precisely define the Area supplied by the following transformer stations: Brant TS, Powerline MTS and Brantford TS.

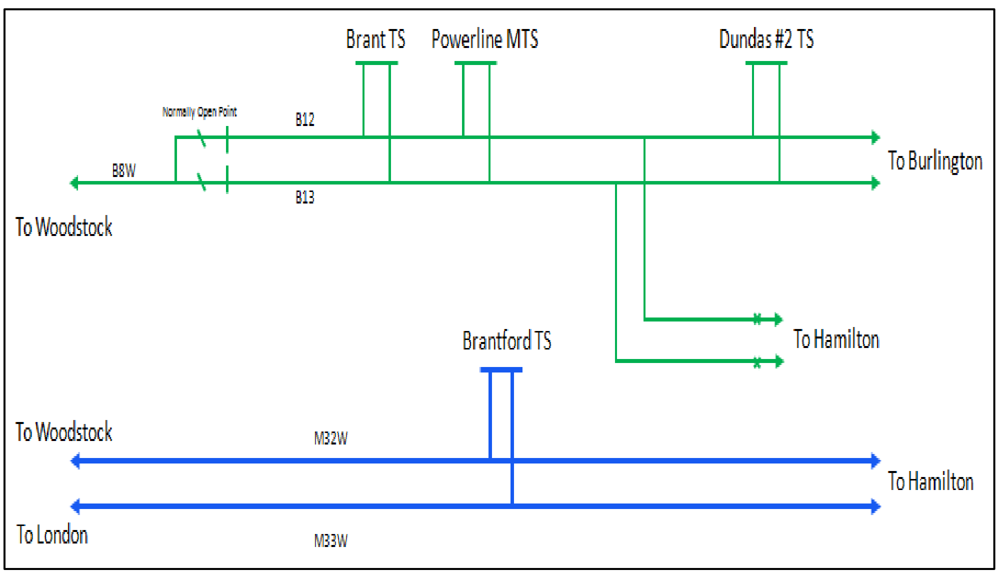
For the purposes of this IRRP, the transmission system in the Brant Area is further divided into two sub-systems:

1. The Brant Powerline sub-system: customers supplied from Brant TS and Powerline MTS via the B12/B13 115 kV transmission line; and
2. The Brantford TS sub-system: customers supplied from Brantford TS via the 230 kV transmission line M32W/M33W.

While there is some emergency transfer capability between the two Brant Area sub-systems, they are normally operated independently.

These two sub-systems are shown in Figure 4-2 below.

Figure 4-2: Brant Area Sub-systems

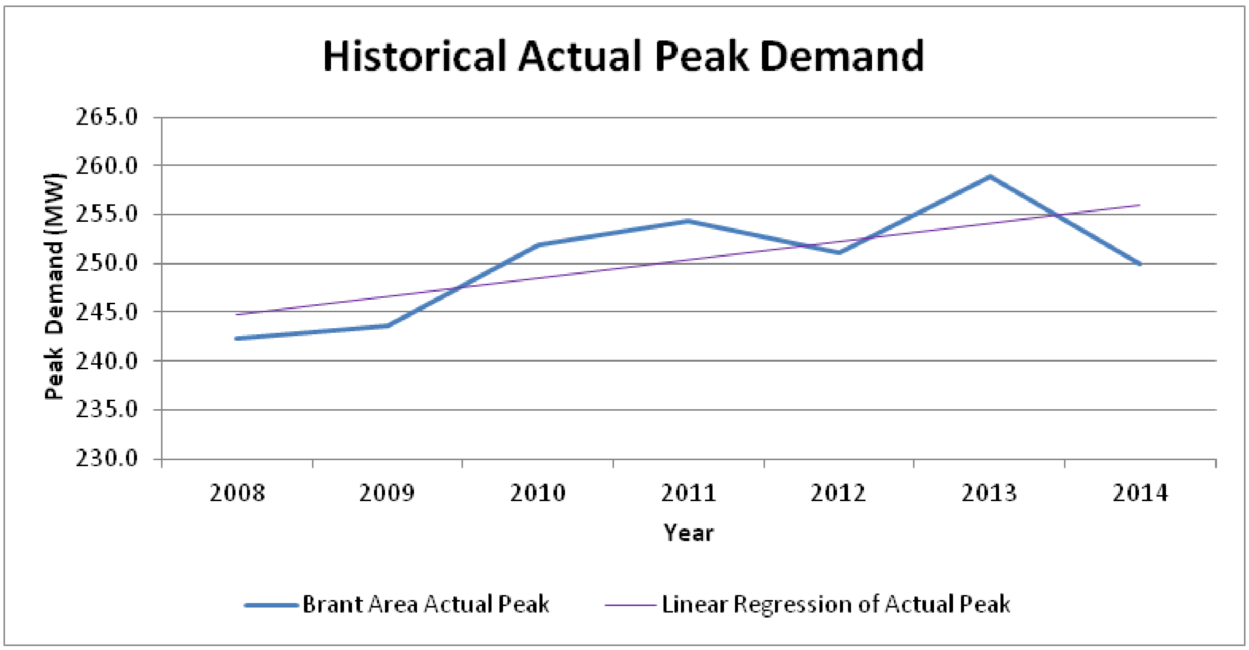


5. Demand Forecast

5.1 Historical Demand

Actual peak electricity demand in the Brant Area has increased moderately from 242 MW in 2008 to 259 MW in 2013, with a modest drop to 250 MW in 2014. This represents a nominal growth rate of 1.9 %, as shown in Figure 5-1. The historical peak demand reflects the weather experienced at the time of the system's coincident peak, and includes the impacts of conservation and DG.

Figure 5-1: Brant Area Historical Electricity Demand



5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak demand requirements of that area. Therefore, regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

The near- and medium-term aspects of a forecast are closely linked to the historical growth experienced in an area and is usually based on loads expected to be in-service within a few years of growth being planned. Unmet needs forecast to arise during this time frame typically require solutions to be developed and implemented during the current planning cycle. The long-term forecast is typically used to identify emerging issues and to set longer-term priorities, with the goal of ensuring near- and medium-term actions will not be stranded or somehow limited in value by the most likely long-term outcomes.

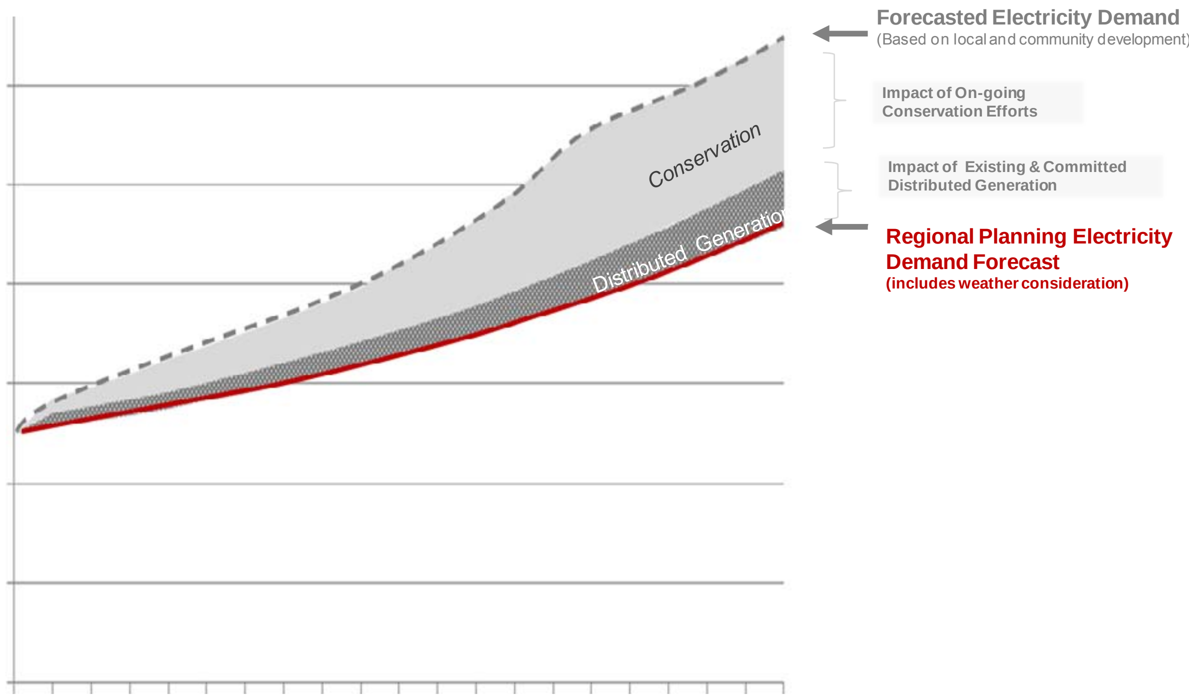
After taking into consideration the combined impacts of conservation and DG, a 20-year planning forecast was produced based on the LDCs' gross demand forecasts and reflecting the 2013 LTEP growth assumptions - this is the expected-growth forecast. Additionally, a second net demand forecast was prepared for the longer term to account for added planning uncertainty, based on the provincial Places to Grow Act - this is referred to as the higher-growth forecast.

5.2.1 Near- and Medium-Term (2014 through 2023)

For the near and medium term, a regional peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs. The LDCs' forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Places to Grow policy. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT, and adjusted to reflect extreme weather conditions, to produce a planning forecast. The planning forecast was then used to assess any growth-related electricity needs in the region.

Using a planning forecast that is net of provincial conservation targets provides consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs. The planning forecast assumes that these conservation targets will be met and that the targets, which are energy-based, will produce the expected local peak demand impacts. Therefore, an important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs.

Figure 5-2: Development of Demand Forecasts



5.2.2 Longer Demand Forecast (2024 through 2033)

For the longer-term outlook, two demand forecast scenarios were developed to reflect the inherent uncertainty associated with forecasting this far in the future.

1. **”Expected Growth”:** This scenario was developed consistent with the growth assumptions embodied in the government’s provincial energy plan. As with the near and medium-term (0-10 years) forecast, the provincial conservation targets up to 2032 are deducted from the gross demand projections to produce a planning forecast net of conservation.
2. **“Higher Growth”:** This scenario was developed to reflect continued development in Brant Area consistent with the projections associated with the province’s *Places to Grow Act, 2005*. This higher-growth forecast scenario is consistent with the growth assumptions associated with the long-term municipal plan projections. As with the near- and medium-term forecasts, the provincial conservation targets up to 2032 are deducted from the gross demand projections to produce a planning forecast net of conservation.

Additional details related to the development of the demand forecasts are provided in Appendix A.

5.3 Gross Demand Forecast

The gross demand forecast for the Brant Area was developed by the Area LDCs based on historical growth rates. The forecast population is based on the Ministry of Finance's Spring 2013[7] population projection for the Brant Census Division, which includes the City of Brantford and Brant County. The Brant Census Division forecasts an average annual population growth rate of 0.9% from 2012-2031.

Area LDC forecasts are based on historical growth rates, supported by Municipal and Regional Official Plans as a primary source for input data. Other common considerations included known connection applications, and typical electrical demand intensity for similar customer types.

Additional background on the methodology used by each LDC to prepare their gross demand forecasts are available in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure, and maintaining reliable supply. Conservation is achieved through a mix of program-related activities, including behavioral changes by customers and mandated efficiencies from building codes and equipment standards ("C&S"). These approaches complement each other to maximize conservation results. The conservation savings forecast for Brant Area are applied to the gross peak demand forecast.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan ("LTEP"), which outlined a provincial conservation target of 30 TWh of energy savings by 2032. In order to represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak demand impacts from the provincial targets in the Brant Area.

[7] Ministry of Finance Spring 2013 population projection
http://www.fin.gov.on.ca/en/economy/demographics/projections/table6.html

It is assumed existing DR already in the base year will continue. Savings from potential future DR resources are not included in the forecast and are instead considered as possible solutions to identified needs.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Brant Area is also applied to offset peak demand requirements. Distributed generation resource development in Ontario has been encouraged by the *Green Energy Act, 2009* and associated procurements such as the Feed-in Tariff ("FIT") program. These procurements have increased the significance of DG in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province. These procurements take into consideration the system need for generation as well as cost.

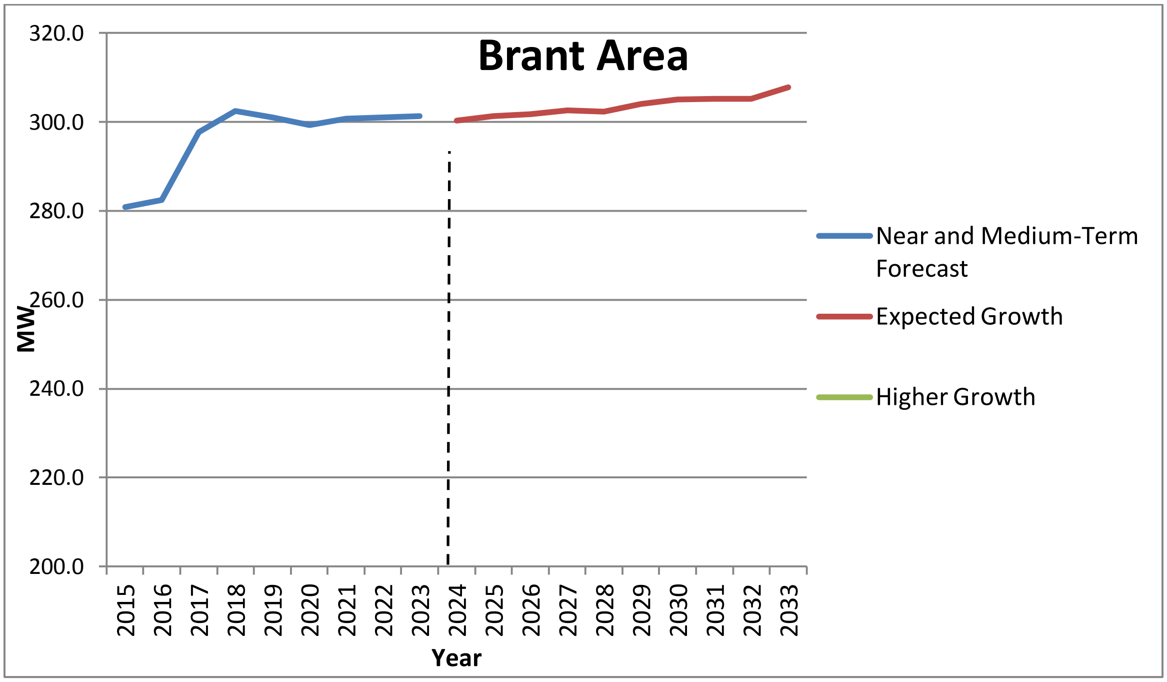
One aspect related to DG that should be noted is that DG resources, such as intermittent renewable generation resources like wind and solar, are not always available at the time of system peak. Therefore, the assumed effective capacity of these facilities (approximately 20 MW), not the full installed capacity, is applied to the Brant Area peak demand.[8] The location, contract capacity, and effective contribution of these resources in the Brant Area can be found in Appendix A.

[8] Effective capacity is the portion of installed capacity that contributes at the time of system peak.

5.6 Planning Forecasts

5.6.1 Total Demand Forecast in Brant Area

Figure 5-3: Brant Area Total Demand Forecast



5.6.1.1 Near- and Medium-Term (2014 through 2023)

The near- and medium-term aspects of a forecast are closely linked to the historical growth experienced in an area and are usually based on loads expected to be in-service within a few years or growth being planned.

The summer peak demand planning forecast of the Brant Area is shown in Figure 5-3 . There is a noticeable step increase in peak demand from the year 2015 to 2018. This is based on customers requesting connection over the next three years. Approximately 37 MW of industrial demand was added to the demand forecast in 2014, which is roughly 15% of the total Area demand. These types of loads often arise on short notice and in large blocks as is evidenced from the in-service dates of 2015 through 2018 and the step changes noticeable in the graph. For example, a forging expansion project will need additional 16 MW supply capacity by 2016.

Table 5-1 below shows the size of the large industrial loads which have been considered in the demand forecast based on LDCs information.

Table 5-1: Near-Term Industrial Load

Proposed Connection Station	LDCs	Estimated Size (MW)
Brantford TS	Brantford Power Inc.	16
Brant TS	Brantford Power Inc.	6
Powerline MTS	Brant County Power Inc.	8
Brantford TS	Brant County Power Inc.	4
Brant TS	Brant County Power Inc.	3
Total Load Added		**37**

The type of block industrial load that has been considered in the near- to medium-term forecast is difficult to forecast for the long term. As seen in Table 5-1, the loads are not concentrated at one station or within one LDC and these types of block loads can also appear with short notice. Consequently, industrial growth incremental to the loads indicated in Table 5-1 were not forecast as part of the medium-term forecast.

5.6.2 Long-Term (2024 through 2033)

For the longer-term outlook, two demand forecast scenarios were developed to reflect the inherent uncertainty associated with forecasting this far in the future.

The "expected-growth scenario" was developed consistent with the growth assumptions embodied in the government's 2013 LTEP. This scenario was a continuation of the forecast used for the near- and medium-term. The expected-growth scenario represents a future with lower electricity demand growth, due to higher electricity prices, increased electricity conservation, and lower energy intensity of the economy. The long-term Area forecast under the expected-growth scenario grows 27 MW from 281 MW to 308 MW. This includes the reduction in demand of approximately 49 MW from conservation, and approximately 18 MW from DG.

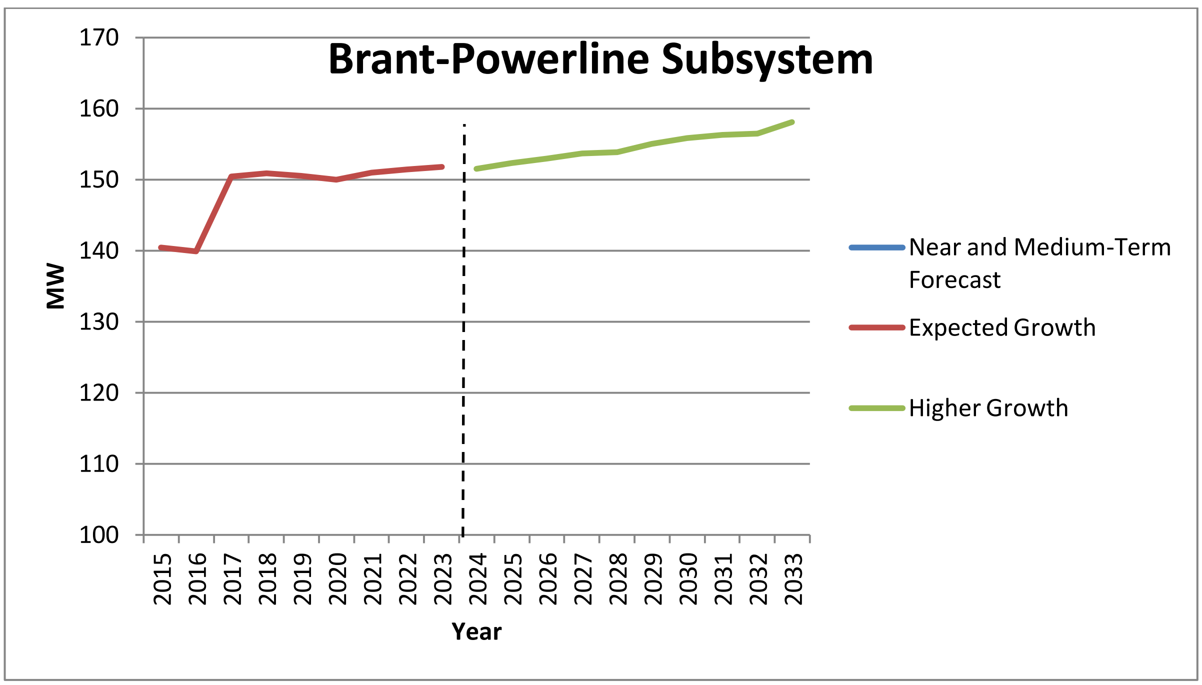
Taking into account the type of load growth the Brant Area has experienced (i.e., fast developing, large block loads), the Working Group examined an additional scenario to consider the possible impact of higher growth on the Area's needs. A higher-growth scenario was developed to reflect continued development in the Brant Area consistent with the projections associated with the province's Places to Grow policy. This forecast scenario is also consistent with growth assumptions associated with the long-term municipal plan projections for the Brant Area.

The higher-growth forecast assumes a total of 57 MW of new savings from conservation targets across the Brant Area over the next 20 years.

5.6.3 Sub-system Forecasts

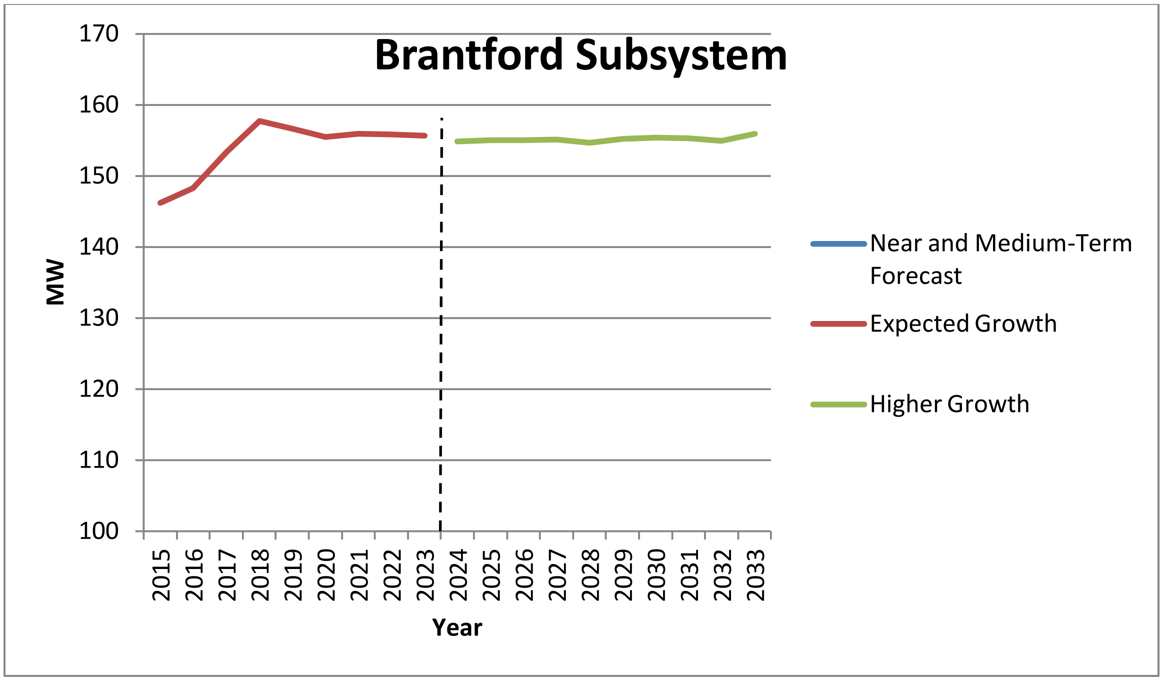
For the Brant-Powerline sub-system, the forecast demand under the expected-growth scenario grows from 140 MW to 158 MW from 2015 to 2033. This includes the reduction of approximately 25 MW from conservation, and approximately 9 MW from DG, with approximately 13 MW of demand reduction through conservation expected in the 2024-2033 timeframe. For the higher-growth scenario, the forecast grows from 157 MW in 2024 to 177 MW in 2033.

Figure 5-4: Brant TS and Powerline MTS Forecast



For the Brantford TS pocket, the forecast demand under the expected-growth scenario grows from 146 MW to 156 MW from 2015 to 2033. This includes the reduction of approximately 25 MW from conservation, and approximately 10 MW from DG. For the higher-growth scenario, the forecast grows from 165 MW in 2024 to 182 MW in 2033.

Figure 5-5: Brantford TS Planning Forecast



6. Electricity System Needs

Based on the demand forecasts, system capability, and the Ontario Resource and Transmission Assessment Criteria ("ORTAC")[9] criteria, the Working Group identified electricity needs in the near-to-medium term (0-10 years), and in the long term (11-20 years). This section describes the identified needs for the Brant Area.

6.1 Needs Assessment Methodology

Provincial assessment criteria and standards (ORTAC) were applied to assess the capability of the existing electricity system to supply forecast electricity demand growth in the Brant Area over the next 20 years (refer to Section 5). These criteria were applied to assess three broad categories of needs.

- Supply capacity requirements were assessed using PSS/E, a power flow simulation tool, to analyze the capability of the existing system, including transmission and local generation infrastructure, to supply load growth. Technical study is provided in Appendix B.
- ORTAC standards were applied to identify areas with needs to address the impacts of potential major supply interruptions. The amount of customer load supplied from specific circuits before and after potential contingencies, and the capability to restore interrupted loads following a contingency, either through transmission system switching or transfers on the distribution system, were assessed in accordance with these criteria.
- Step-down station capacity needs were identified by comparing forecast demand growth to the 10-day Limited Time Rating ("LTR"), or thermal capacity, of the existing stations in the Area, to determine the net incremental requirement for transformation capacity in the Area.

6.2 Ontario Resource and Transmission Assessment Criteria

The ORTAC the provincial standard for assessing the reliability of the transmission system, were applied to assess supply capacity and reliability needs.

The ORTAC includes criteria related to assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements. The latter criteria are relevant to this study and guided the technical studies performed in assessing the electricity system needs

[9] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

in Brant Area. The needs can be broadly categorized as addressing two distinct aspects of reliability: (1) providing supply capacity, and (2) limiting the impact of supply interruptions. Further details on the application of these criteria are provided in Appendix B.

6.3 Near- and Medium-Term Needs

Near- to medium-term needs often require action immediately to ensure that a solution is in place to address the need by the time it arises.

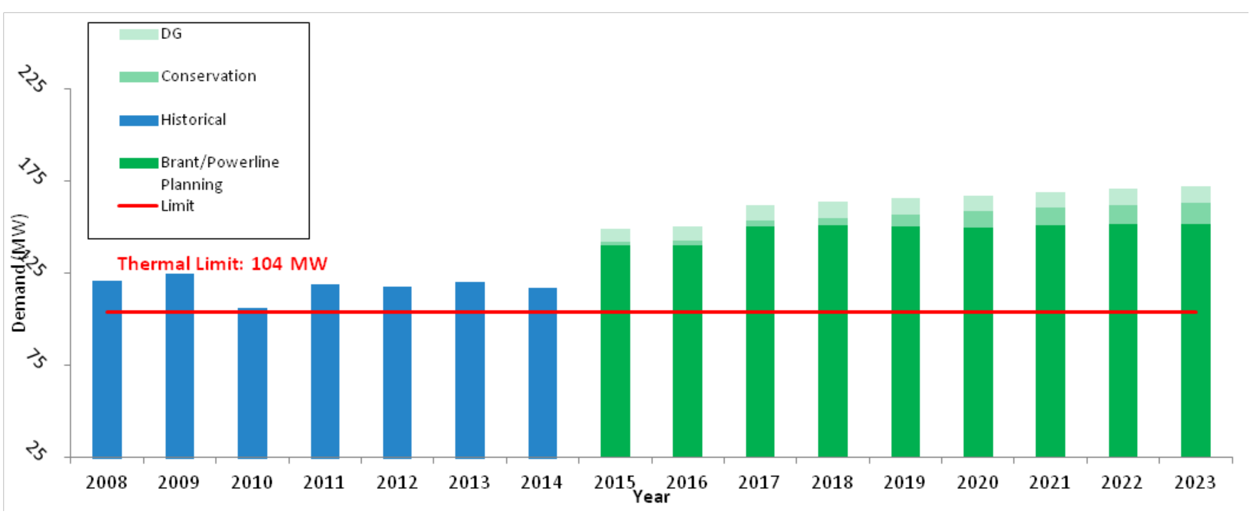
6.3.1 Need for Additional Supply Capacity

Brant-Powerline Sub-system

Today, the B12/B13 115 kV transmission line serving the Brant-Powerline sub-system has a LMC of approximately 104 MW. This limit is based on the violation of the voltage criteria following the loss of one of the B12/13 circuits.

As shown in Figure 6-1 below, peak demand for this sub-system has already exceeded the LMC, and is forecast to continue to exceed this limit throughout the study period.

Figure 6-1: Historical and Forecast Electricity Demand and Supply Capability in the Brant-Powerline Sub-system



Based on the forecast, additional capacity is required to meet current and future electricity demand in the Brant-Powerline sub-system. Until additional capacity is provided, operating measures such as temporary load transfers or interruption of load following a single contingency will be required. The existing system does not meet the ORTAC criteria for supply capacity in the near and medium term.

Brantford TS Sub-system

The Brantford TS sub-system meets the ORTAC criteria for supply capacity for the reference forecast throughout the study period.

6.3.2 Load Restoration Needs

Brant -Powerline Sub-system

Brant TS and Powerline MTS sub-system meets the ORTAC restoration criteria until the end of the study period.

Brantford TS Sub-system

The Brantford TS sub-system meets the ORTAC restoration criteria until the end of the study period.

6.3.3 Conclusion Near- and Medium-Term Electricity Needs

The Brant-Powerline sub-system has already exceeded the LMC of the supply circuits and there is further significant step load growth identified by the LDCs forecast over the next five years. Therefore, an urgent need has been identified to provide additional capacity to the Brant-Powerline 115 kV sub-system.

6.4 Long-Term Needs

To assess needs in the long term, two demand forecast scenarios were considered: expected-growth and high-growth (see Section 5.2). As described in Section 7, the near- and medium-term plan is expected to meet the needs of the Area until the end of the study period.

However, if Area demand is consistent with the higher-growth scenario, additional electricity capacity needs may arise before the end of the study period. Thus, the analysis in this section is to address a scenario where there is a potential need for additional long-term Area supply.

Higher Growth Scenario

The Brant Area peak demand is forecast to grow to 352 MW by 2033 under the higher-growth scenario. At the sub-system level, the Brant-Powerline sub-system is forecast to grow to 177 MW and the Brantford TS sub-system to 182 MW under this scenario by 2033.

Table 6-1: Capacity Gap in 2033 under Higher-Growth Scenario

	Limit after Near- and Medium-Term Solutions (MW)	Higher Growth Forecast demand in 2033 (MW)	Higher Growth Capacity Gap in 2033 (MW)
Brant-Powerline sub-system	165	177	12
Brantford TS sub-system	178	182	4
Brant Area	343	352	9

In the long term, the Brant Area electricity system's ability to supply load will be constrained if additional industrial block loads arise in the Area, or higher demand growth is experienced consistent with the higher-growth scenario (Section 5.6.2). Supply constraints will leave the LDCs unable to connect new customers without additional supply in the Area. Consequently, the Working Group agreed to develop a strategic plan to consider higher demand growth based on the Places to Grow assumptions or additional industrial block loads.

7. Near- and Medium-Term Plan

The plan to address the near- and medium-term electricity needs of the Brant Area consists of specific actions and projects for immediate implementation, reflecting the urgency of the needs and the load time for developing solutions (refer to Section 6.3).

This section describes the alternatives considered in developing the near-term plan for the Brant Area and provides details and rationale for the recommended plan.

7.1 Alternatives for Meeting Near- and Medium-Term Needs

In developing the near- and medium-term plan, the Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the Brant Area.

7.1.1 Conservation

Conservation was considered as the first alternative to meet the electricity needs through the development of a planning forecast that includes the peak-demand effects of the provincial conservation targets,[10] along with contracted DG (see Sections 5.4 and 5.5). These conservation resources account for approximately 30 MW, or approximately 40% of the forecast demand growth during the first 10 years of the study period (through 2024).

Additional conservation beyond the targeted amounts included in the demand forecast may assist in meeting growth-related needs, such as the need to provide additional LMC in the Brant-Powerline sub-system. To meet these needs with conservation, an additional 50 MW of peak-demand reductions (i.e., 45% of sub-system load), incremental to the forecast of 12 MW from the LTEP conservation target would be required by 2023. This 50 MW plus the 12 MW targeted conservation amounts to approximately 45% of sub-system load. Given the immediate need and magnitude of the needs relative to the LTEP conservation target, the Working Group agreed that additional conservation beyond the targeted amounts is not a feasible option to meet the needs of the Area. However, efforts in the near- and medium-term should be focused on ensuring that the provincial conservation targets are met and monitoring the associated

[10] The provincial targets are for energy and have to be converted to capacity to calculate impact on peak demand by conservation

peak-demand savings that were assumed for the Brant Area. Therefore, conservation efforts to meet this goal are included as a recommendation in the near-term plan.

A provincial DR pilot is expected to roll out in the 2015-2016 time period. The Working Group believes it is prudent to consider this pilot program for the Brant Area to investigate opportunities, costs and feasibility in order to better understand its potential to address the Area's long-term supply capacity needs. A pilot can provide insights into the existence of willing DR participants in the Area. Knowledge and experience gained by way of a pilot will be useful when DR capacity markets are implemented by the IESO in the future and will help to address system as well as regional needs in the Brant Area and other areas of the province. At this time large scale use of DR has not been used as a solution to address local area's needs. Thus, a DR pilot program for the Brant Area could demonstrate its potential to be a technically feasible and cost-effective solution to provide a capacity buffer for the Area and defer larger and more costly infrastructure alternatives.

7.1.2 Local Generation

While in general local generation has the potential to meet both supply capacity and load restoration needs, this alternative was ruled out by the Working Group for meeting the near- to medium-term needs.

For the Brant Area, a natural gas plant for peak supply could meet the capacity needs at a cost of approximately $700-1000/kW with a 2-3 year in-service lead time.

It is the Working Group's view that local generation is not a cost effective option when compared to the recommended transmission options discussed below. Local generation is also not able to maximize the use of the existing Brant-Powerline sub-system infrastructure.

7.1.3 Transmission

Since the LMC of circuits B12/13 is primarily voltage limited, a number of voltage support options were considered to meet the near- and medium-term capacity needs of the Brant Area.

Capacitor Banks at Powerline MTS

Capacitor banks provide reactive support, boosting the voltage in an area. In doing so, they increase the voltage limit which is the first limiting factor in the 115 kV Brant-Powerline sub-system. The IESO and Hydro One studies have shown that 30 MVAR of reactive support at

Powerline TS can raise the LMC of the Brant-Powerline sub-system to 125 MW from 104 MW, thus increasing the useable capacity in the 115 kV Brant-Powerline sub-system. Capacitor banks also have relatively short 1-2 year in-service lead times. This option would cost approximately $1.0 million or $48/kW based on preliminary cost estimates by the LDC's and Hydro One.

Switching Facilities at Brant TS

This option connects the B8W and B12/13 circuits by installing three 115 kV breakers to close the existing normally open points. This option by itself can provide approximately 40 MW of additional supply to the limiting B12/13 circuits. Combined with the capacitor banks option as described above, the LMC of the Brant-Powerline sub-system can be further increased to approximately 165 MW.

It is estimated that the breakers can be in-service by 2017 and the budgetary estimate is $12-15 million based on Hydro One's preliminary cost estimates or $300-$375/kW. Hydro One and LDCs can together develop an implementation plan.

7.1.4 Distribution Options

Load transfers move load from one station to another and are currently used in the Brant Area on a temporary basis to maintain the loading on the 115 kV radial pocket within its LMC during peak demand conditions.

Depending on system conditions, Brantford Power has indicated that it has the ability to transfer up to 10 MW on a temporary, short-term basis from Powerline MTS and/or Brant TS to the Brantford TS. However, due to existing demand and future load growth, Brantford Power does not have the capacity at Brantford TS for permanent load transfers from the 115 kV sub-system. The incremental load at Brant Powerline sub-system in 2015 that is over the current 104 MW limit is expected to be 36 MW; this amount of load would be enough to exceed the limit at the Brantford TS. Therefore, load transfers are not a solution for the Area's capacity needs, as the surplus capacity that exists in the Area will be used up immediately.

7.2 Recommended Near- and Medium-Term Plan

The Brant Area Working Group assessed these alternatives in Section 7.1 as the basis for the following recommendations. Successful implementation of this plan will address the Area's electricity needs until the end of the study period.

To ensure the reliability of the Brant-Powerline sub-system before any permanent solutions are put in place, temporary load transfers will continue to be used in the near and medium term as required by the LDCs to address operational requirements.

Conservation

Meeting the conservation targets is assumed before identifying residual needs for the Area. The Working Group recommends that LDCs' conservation efforts be focused on measures that balance the needs for energy savings to meet the Conservation First targets while maximizing peak-demand reductions. Monitoring of conservation success, including measurement of peak demand savings, will be an important element of the near- and medium-term plan, and will also lay the foundation for the long-term plan by reviewing the performance of specific conservation measures in the Brant Area, and assessing potential in the Area for further conservation efforts.

Capacitor Banks at Powerline MTS

The Working Group recommended the installation of capacitor banks at Powerline MTS to raise the LMC of the circuits to 125 MW. The implementation of the capacitor bank solution was assigned to Hydro One by way of a letter[11] from the former OPA in February 2014. The capacitor banks are expected to be in-service for summer 2015 and the implementation is being undertaken by Brantford Power Inc. and Brant County Power Inc.

Switching Facilities at Brant TS

The Working Group recommends utilizing the existing B8W circuit by adding three breakers on circuits B12/13 and B8W. Combined with the capacitor banks, the LMC of the Brant-Powerline sub-system can be further increased to approximately 165 MW. As shown in Figure 7-1, the supply capacity needs under the expected-growth forecast will be addressed by implementing these two stages of transmission reinforcement.

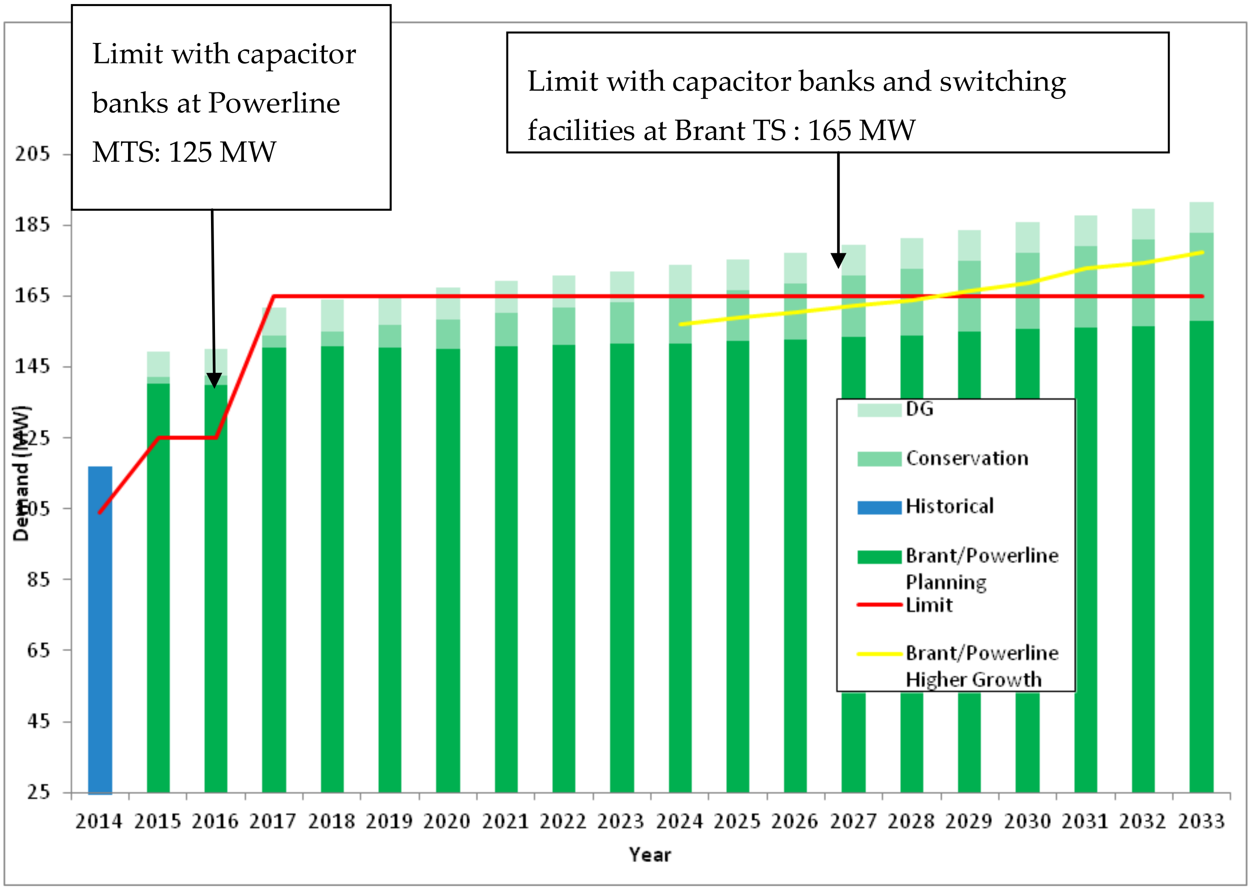
Demand Response

The Working Group has also considered investigating DR opportunities in the Brant Area by way of a DR pilot. The pilot program would be undertaken by the IESO in conjunction with

[11] http://www.hydroone.com/RegionalPlanning/Burlington/Documents/OPA Letter - Burlington Nanticoke - Brant.pdf

Area LDCs to investigate opportunities, costs and quantity of DR available in the Brant Area. Knowledge and experience gained by way of a pilot will be useful to provide options for addressing potential future capacity needs under a high-growth scenario.

Figure 7-1: Brant-Powerline Sub-system Planning Forecast and LMC



As shown in Figure 7-1, the recommended near- and medium-term solutions meet the needs of the Area until the end of the study period for the expected-growth scenario. These solutions are foundational for any longer-term considerations should electricity demand growth correspond with the higher-growth scenario or the Area experiences greater industrial load growth than is forecast.

7.3 Implementation of Near- and Medium-Term Plan

To ensure that the near-term electricity needs of Brant Area are addressed, it is important that the near- and medium-term plan recommendations be implemented in a timely manner. The specific actions and deliverables associated with the near- and medium-term plan are outlined in Table 7-1 below, along with their recommended timing, and the parties with lead responsibility for implementation.

Table 7-1: Implementation of Near- and Medium-Term Plan for the Brant Area

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Implement conservation and DG	Develop CDM plans	LDCs	May 2015
	Implement LDC CDM programs	LDCs	2015-2020
	Conduct Evaluation, Measurement and Verification (EM&V) of programs, including peak-demand impacts, and provide results to Working Group	IESO	annually
	Continue to support provincial DG programs	LDCs/IESO	ongoing
2. Add capacitor banks at Powerline MTS	Design, develop and construct capacitor banks at Powerline MTS	Brantford Power Inc. and Brant County Power Inc.	ongoing and expected to be in-service summer 2015
3. Add switching facilities at Brant TS	Design, develop and construct new switching facilities at Brant TS	Hydro One, Brantford Power Inc. and Brant County Power Inc.	in-service summer 2017
4. Consider DR pilot for the Area	Continue to investigate opportunities for a DR pilot in the Brant Area	IESO	ongoing

8. Long-Term Plan (2024 through 2033)

The approach to developing long-term electricity plans is somewhat different than for near- or medium-term plans. There is inherently greater certainty in assessment of near- and medium-term electricity needs. For these needs, specific projects may need to be committed to ensure they are available to meet the forecast need. For longer-term electricity needs, there is an opportunity to develop and explore a broader set of options, as specific projects typically do not need to be committed urgently. Instead, the focus is on identifying potential need and on exploring alternatives to meet these needs. There is flexibility to assess alternatives that are not in widespread use but which show promise for the future. There is also opportunity to engage with stakeholders and communities to identify alternatives, to set out preliminary actions, and to monitor actual load growth and the underlying drivers. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to gauge the success and future potential of conservation measures; test out emerging technologies; engage with communities and stakeholders; coordinate with municipal or community energy planning ("MEP/CEP") activities; to lay the foundation for well-informed decisions in the future; and support decision-making in the next iteration of the IRRP.

An important consideration in developing a long-term plan is recognizing the timeframe within which decisions will need to be committed. This involves integrating the projected timing of needs with the expected in-service lead times when identifying and considering alternatives. The longest lead time among all the possible alternatives is usually associated with new major transmission infrastructure, which typically requires 5-7 years to bring into service (including conducting development work, gaining regulatory and other approvals, construction and commissioning).

Based on the expected timing of the long-term needs in the Brant Area and the 5-7-year lead time for major infrastructure alternatives, the Working Group expects that a decision on the long-term plan will likely be required around 2028. Therefore, it is recommended that demand growth be monitored regularly as part of the implementation of this IRRP and, if necessary, that the IRRP be revisited ahead of the 5-year schedule mandated by the OEB's regional planning process.

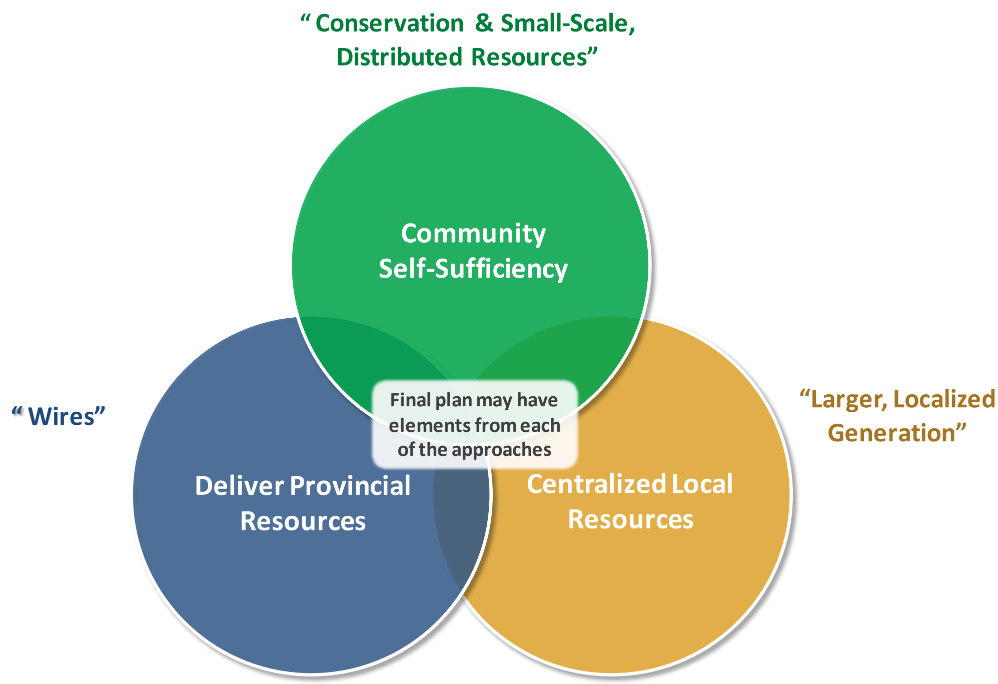
The following sections describe various approaches for meeting the long-term electricity needs of the Brant Area, and lay out recommended actions to develop the longer-term plan, and their implementation.

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increasing community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning, while still technically feasible, may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 8-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 8-1: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; demand response; distributed generation and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use to address regional capacity needs, for regions with

long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options to provide firm capacity resources at the local level before long-term plan commitment decisions are required. The success of this approach depends on early action to explore potential and develop options, and on the local community taking a lead role. This could be through a MEP/CEP process, or an LDC or other local entity taking initiative to pursue and develop options.

The intent of this framework is to identify which approach is to be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches, and there will necessarily be some overlap between them. For example, provincially mandated conservation targets will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. In fact, it is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. Once the decision on the basic approach is made, the plan is developed around that approach, which affects the relative balance of conservation, generation, and "wires" in the plan.

8.1.1 Delivering Provincial Resources

Under a "wires" based approach, the long-term needs of Brant Area would be met primarily through transmission and distribution system enhancements. If the substantial needs forecast under the higher-growth scenario or additional industrial load arise, this could involve major new transmission development to deliver power from the major sources supplying the Area to where the power is needed.

Transmission options typically provide large capacity additions and can take 3-5 years to come into service from time of initiation. Such options could also require approval of leave to construct to the OEB as well as environmental assessments.

8.1.2 Large, Localized Generation

Addressing the Brant Area's long-term needs primarily with large local generation would require that the size, location and characteristics of local generation facilities be consistent with the needs of the Area. As the requirements are for additional capacity during times of peak demand, a large generation solution would need to be capable of being dispatched when needed and to operate at an appropriate capacity factor. This would mean that peaking facilities, such as a simple-cycle gas turbine ("SCGT") technology, would be more cost-effective than technologies designed to operate over a wider range of hours, or that are optimized to a host facility's requirements.

Based on the long-term demand forecast, a local generation source could be helpful if it is located at Brant TS or Powerline MTS to further relieve the 115 kV sub-system. The cost of this option would depend on the size and technology of the units chosen, as well as the degree to which they can contribute to a provincial capacity or energy need.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Brant Area through a Community Self-Sufficiency approach requires leadership from the community itself to identify opportunities and deploy solutions. As this approach relies to a great degree on emerging technologies, there will be a need to develop and test out solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

In the Brant Area, this approach will be led by municipalities, the LDCs and First Nations communities if desired in identifying and developing opportunities.

8.2 Recommended Actions in Support of Long-Term Plan

At this time, while the Working Group does not recommend any specific commitment of investment and facilities to addresses potential longer-term needs (beyond 2025). To prepare for potential longer-term electricity load growth in this Area, the Working Group will investigate opportunities and potential for further cost-effective conservation and generation, as well as any relevant transmission investments.

Monitoring of growth in electricity demand and the achievement of conservation and DG targets in the Brant Area, will also be key components of ongoing electricity planning in the region and the needs and the options in the longer term will be reviewed in subsequent Burlington-Nanticoke regional planning studies.

1. Monitor Load Growth and Conservation Achievement and DG Performance

On an annual basis, the IESO will coordinate a review of conservation achievement, the uptake of provincial DG projects, and actual demand growth in the Brant Area. This information will be used to track the expected timing of long-term needs to determine when a decision on the long-term plan is required. Information on conservation and DG performance will also provide useful feedback into the ongoing development of these options as potential long-term solutions.

Additionally, the IESO will monitor results and incorporate lessons learned from the DR pilot, if it is implemented.

As the long-term needs for the Brant Area becomes more certain, additional measures to meet these needs, including but not limited to, large infrastructure investments, can be triggered in the next planning cycle with appropriate lead times to ensure that the needs will be met.

2. Undertake community engagement

Broad community and public engagement is essential to development of a long-term plan. As no long-term needs have been identified for the Brant Area, there is no requirement at this time for engagement on long-term options.

However, a LAC may be established for the broader Burlington to Nanticoke region when the regional planning process is complete for the whole region.

A LAC's purpose is to provide input and advice on engagement plans for an area or region. It is expected that a LAC will consist of community, First Nations and Métis representatives and stakeholders. Advice from the LAC will be incorporated in developing engagement plans for an area/region.

3. Continue ongoing work to develop transmission/generation options

The IESO and Hydro One will continue working with the working group to evaluate the transmission or generation options to meet the potential long-term needs.

8.3 Recommended Actions and Implementation

A number of alternatives are possible to meet the region's long-term needs if they arise. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives, to support decision-making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

The recommended actions and deliverables for the long-term plan are outlined in Table 8-1, along with their recommended timing, and the parties with lead responsibility for implementation are assigned.

Table 8-1: Implementation of Near-Term Actions in Support of the Long-Term Plan for the Brant Area

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Undertake engagement	Undertake public/community engagement as required	LDCs	2015-2017
	Engage with First Nations communities and the Métis Nation of Ontario	IESO	2015-2017
2. Monitor load growth, CDM achievement, and DG uptake	Prepare annual update to the Working Group on demand, conservation and DG trends in the Area, based on information provided by Working Group	IESO	Annually
	Identify long-term CDM potential	IESO	2016
3. Continue ongoing work to develop transmission / generation options	The IESO and Hydro One will continue working with the working group to evaluate the transmission or generation options to meet the potential long-term needs.	IESO/Hydro One	As required based on monitoring of growth
4. Initiate the next regional planning cycle early, if needed	Based on results of monitoring (see recommendation 4), commence the next regional planning cycle in advance of the OEB-mandated schedule, if needed, to enable sufficient time to develop options	IESO	As required

9. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles. It also addresses activities undertaken to date for the Brant Area IRRP and those that will take place to discuss the long-term needs identified in the plan and obtain input in the development of options.

A phased community engagement approach has been developed for the Brant IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table (see Figure 9-1). These principles were articulated as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process and they are now guiding the IRRP outreach with communities.

Figure 9-1: Summary of Brant IRRP Community Engagement Process

Creating Transparency:

Creation of Brant IRRP Information Resources

- Dedicated Brant IRRP web page created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page added to Hydro One website, and information posted on LDC websites
- Self-subscription service established for Brant IRRP for subscribers to receive regional specific updates
- Status: complete

- Presentation and discussion at four group meetings with municipal planners from across the planning region
- Information provided to First Nation communities with known interest in the planning area with an invitation to meet
- Presentation and discussion with First Nation communities as requested
- Information provided to Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

- Presentations for Municipal Councils, First Nation communities and the Métis Nation of Ontario as requested
- Webinar to discuss electricity needs and near-term solutions
- Outreach with the broader community and formation of a Local Advisory Committee to be determined following the launch of the Burlington sub-region IRRP also within the Burlington - Nanticoke planning region
- Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the Brant IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former OPA) website to provide a map of the regional planning Area, information on why the plan was being developed, the Terms of Reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the Brant IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the Brant IRRP was meeting with representatives from the municipalities and First Nations communities in the region. For the municipal meetings, presentations were made to the Brant Area municipal planners at two group meetings held in Brant and Brantford in 2013, and again in 2015 after Area load forecasts were updated due to expected increases in near-term demand. The IESO held a separate meeting with representatives of the Six Nations Elected Council.

During these meetings, key topics of discussion involved confirmation of increased growth projections for the Area, which included addressing the near- and medium-terms needs through the installation of capacitor banks at the Powerline MTS and switching facilities at Brant TS, and continued CDM efforts, with the possibility of a DR pilot program in the Area, and potential actions to prepare for the long-term need if it materializes. Invitations to meet to discuss the Brant IRRP were also extended to the Mississaugas of the New Credit First Nation and to the Haudenosaunee Confederacy Chiefs Council. The IESO remains committed to responding to any questions or concerns from other communities who may have an interest in the planning Area.

Information on these project-level engagements, if required, will be provided on Hydro One's website and will also be listed on the IESO's Brant IRRP main webpage.

Bringing Communities to the Table

This engagement will begin with a webinar hosted by the working group to discuss the plan and potential approaches of possible long-term options. Presentations on the Brant IRRP will also be made to Municipal Councils, First Nations communities and the Métis Nation of Ontario on request.

Decision on broader community outreach activities, including whether to form a LAC will be made after the launch of the Bronte sub-region IRRP that is also within the Burlington – Nanticoke planning region. As LACs are generally formed at the regional planning level, not the sub-region level, additional work is required on the Bronte sub-region IRRP prior to initiating the formation of the LAC. In general, LACs are established as a forum for members to be informed of the regional planning processes. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement, and planning processes. Local Advisory Committee meetings are open to the public and meeting information is posted on the IESO website.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[12] available on the IESO website.

Information on outreach activities for the Brant IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Burlington to Nanticoke IRRP.

[12] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-regional-energy-planning-review

10. Conclusion

This report documents an IRRP that has been carried out for the Brant Area, a sub-region of the Burlington to Nanticoke planning region.[13] The IRRP identifies electricity needs in the Area over the 20-year study period from 2014 to 2033, recommends a plan to address near- and medium-term needs, and identifies actions to develop broad options for the long term.

Implementation of the near-term plan is already underway, with the LDCs developing conservation plans consistent with the Conservation First policy and infrastructure projects being developed by the LDCs and Hydro One.

To support development of the long-term plan, a number of actions have been identified to monitor growth, engage with the community, and develop alternatives in the Area, and responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the Brant Area IRRP. A RIP is not required because transmission infrastructure planning to address the needs identified are already at the project level.

The planning process does not end with the publishing of this IRRP. Communities will be engaged in the development of the options for the long term. In addition, the Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the Area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the long term under the higher-growth scenario or arrival of additional industrial load. If demand growth follows the expected-growth scenario or conservation achievement is higher than forecast, the plan may be revisited according to the OEB-mandated 5-year schedule. This outcome would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

[13] The Brant and Bronte area of Oakville and Burlington form part of the larger Burlington to Nanticoke region.

Greater Ottawa

REGIONAL INFRASTRUCTURE PLAN

December 2, 2015

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Hydro Ottawa Limited
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Hydro Hawkesbury Inc.
Ottawa River Power Corporation

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

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

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EXECUTIVE SUMMARY

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

The participants of the RIP Working Group included members from the following organizations:

- Hydro Ottawa Limited
- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation

This RIP provides a consolidated summary of needs and recommended plans for both the Ottawa Area Sub-Region and Outer Ottawa Area Sub-Region that make up the Greater Ottawa Region for the near term (up to 5 years) and the mid-term (5 to 10 years). No long term needs and associated plans (10 to 20 years) have been identified.

This RIP is the final phase of the regional planning process and it follows the completion of the Ottawa Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the Outer Ottawa Area Sub-Region's Needs Assessment ("NA") Study by Hydro One in July 2014.

The major infrastructure investments planned for the Greater Ottawa Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Almonte TS: addition of breaker to sectionalize line M29C	November 2015	$4.7M
2	Russell TS and Riverdale TS: construction of feeder ties to allow extra load transfers	2017-2020	$2.0M
3	Lisgar TS: replacement of transformers T1 and T2	December 2017	$13.9M
4	Hawthorne TS: replacement of autotransformers T5 and T6	May 2018	$15.7M
5	Overbrook TS: replacement of transformers T3 and T4	June 2018	$1.1M(1)
6	115kV Circuit A6R: additional tap to off load Circuit A4K	June 2019	$9-11M
7	Hawthorne TS: replacement of transformers T7 and T8 and add one 44kV feeder position	October 2019	$1.1M(2)
8	King Edward TS: Replace Transformer T4	June 2021	$12M

(1) The transformers are at end of life and are being replaced as part of Hydro One sustainment program. The cost shown here represents the incremental cost of installing the next larger size units.
(2) Incremental cost for larger transformer only.

The IRRP study had also identified the need for additional 230/115 kV autotransformation capacity at Merivale TS and provision for a supply for a new station in the southwest area. The options to address these needs are still being studied by the Working Group and as part of the IESO community engagement activities. The Working Group expects to finalize recommendation to address these needs by summer 2016.

Investments to address the other mid-term needs, for cases where a decision is not required until 2020, will be reviewed and finalized in the next regional planning cycle.

No long term needs were identified at this time. As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE GREATER OTTAWA REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the joint study carried out by Hydro One, Hydro Ottawa Limited (“Hydro Ottawa”), Hydro Hawkesbury Inc. (“Hydro Hawkesbury”), Ottawa River Power Corporation (“ORPC”) and the Independent Electricity System Operator (“IESO”) in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of Highway 43. At the center of this region is the City of Ottawa. Electrical supply to the Region is provided from fifty-two 230 kV and 115 kV step-down transformer stations. The summer 2015 area load of the Region was about 1800 MW. The boundaries of the Region are shown in Figure 1-1 below.

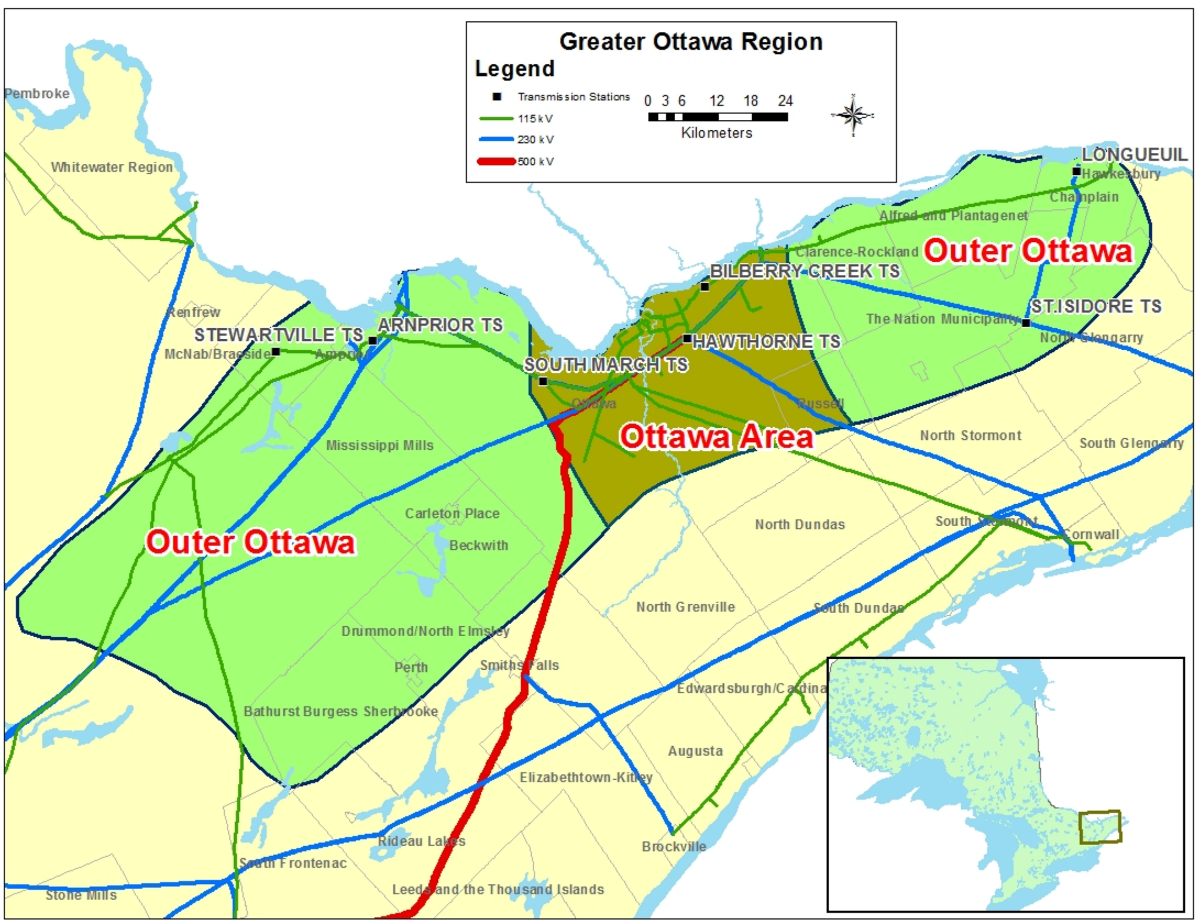

Figure 1-1 Greater Ottawa Region

1.1 Scope and Objectives

This RIP report examines the needs in the Greater Ottawa Region. Its objectives are to: identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Local Plan, and/or Integrated Regional Resource Plan); assess and develop a wires plans to address these needs; provide the status of wires planning currently underway or completed for specific needs; and identify investments in transmission and distribution facilities or both that should be developed and implemented to meet the electricity infrastructure needs within the region.

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan).
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as follows:
- Section 2 provides an overview of the regional planning process.
- Section 3 describes the region.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. Since the Ottawa Sub-Region was in transition to the new regional planning process, the IESO led IRRP engagement for this sub-region was initiated after the completion of the IRRP.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The regional planning process specifies a 20 year planning assessment period for the IRRP. No specific period has been specified for the RIP. The RIP focuses on the wires options and, given the forecast uncertainty and the fact that adequate time is available to identify and plan new wire facilities in subsequent planning cycles, a study period of 10 years is considered adequate for the RIP. The only exception would be the case where major regional transmission is required for an area with limited or no transmission facilities. In these cases the RIP would review and assess longer term needs if identified in the IRRP.

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

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

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

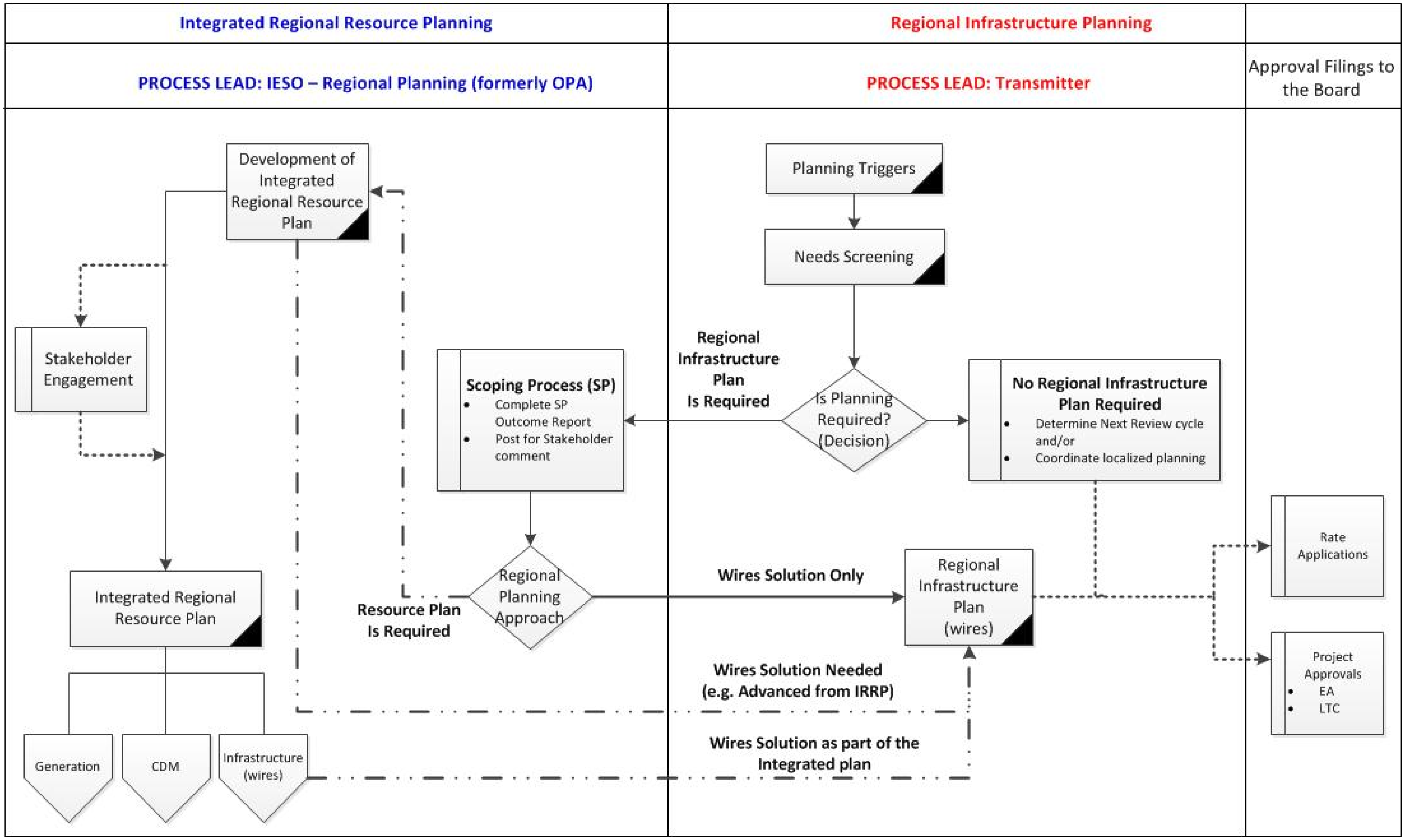

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

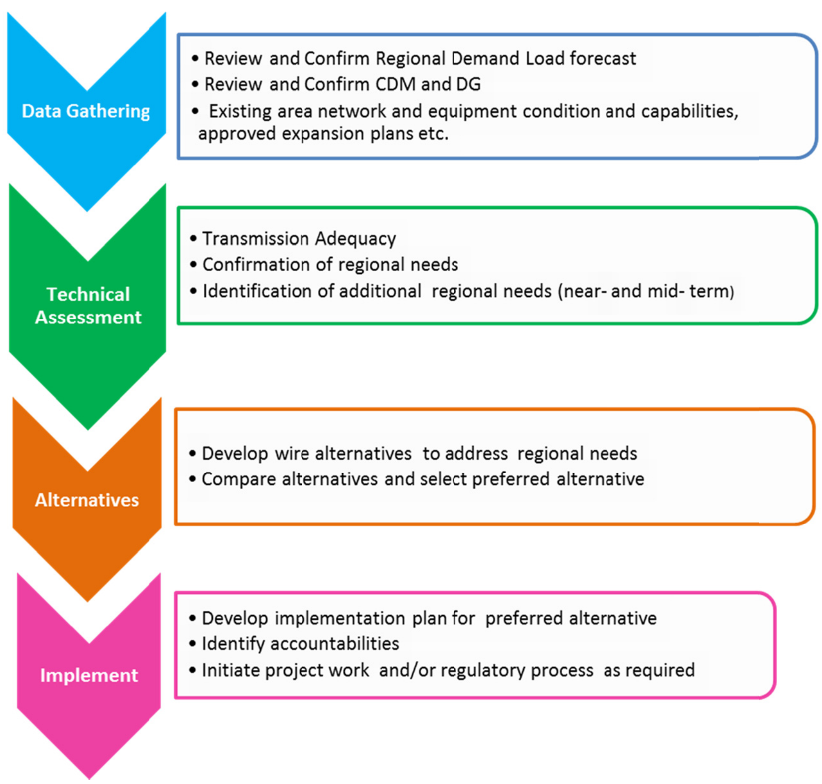

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER OTTAWA REGION COVERS THE MUNICIPALITIES BORDERING THE OTTAWA RIVER FROM ARNPRIOR IN THE WEST TO HAWKESBURY IN THE EAST AND NORTH OF HIGHWAY 43. AT THE CENTER OF THIS REGION IS THE CITY OF OTTAWA (SEE FIGURE 3-1). ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTY-TWO 230 KV AND 115 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1840 MW.

Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230 kV Hawthorne TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into two sub-regions as shown in Figure 1-1 and described below:

- The Ottawa Sub-Region comprises primarily the City of Ottawa. It is supplied by two 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS, eight 230 kV and thirty-three 115 kV transformer stations stepping down to a lower voltage. Local generation in the area consists of the 74 MW Ottawa Health Science Non-Utility Generator ("NUG") located near the downtown area and connected to the 115 kV network. The Ottawa Sub-Region is shown in Figure 3-1 below.

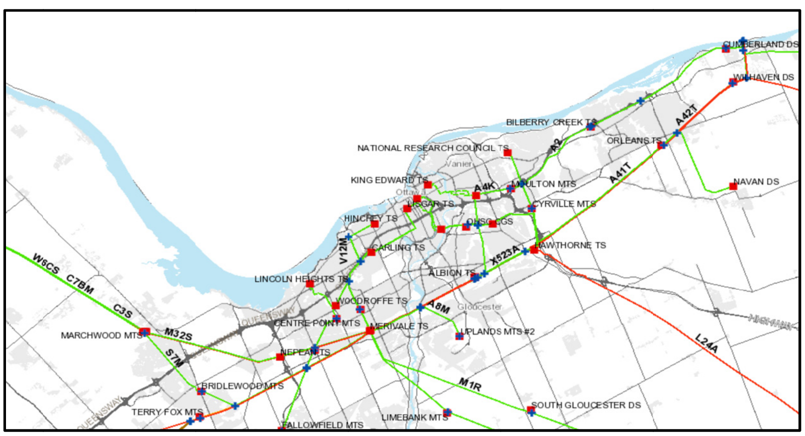

Figure 3-1 Ottawa Sub-Region

Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the outlying areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations and distribute it to the end users, i.e. industrial, commercial and residential customers.

- The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area (shown in Figure 3-2) is served by three 230 and five 115 kV step-down transformer stations. Hydro One Distribution and Hydro Hawkesbury are the LDCs in the area that distribute power from the stations to the end use customers. It also includes a large industrial customer, Ivaco Rolling Mills, in L'Orignal, Ontario.

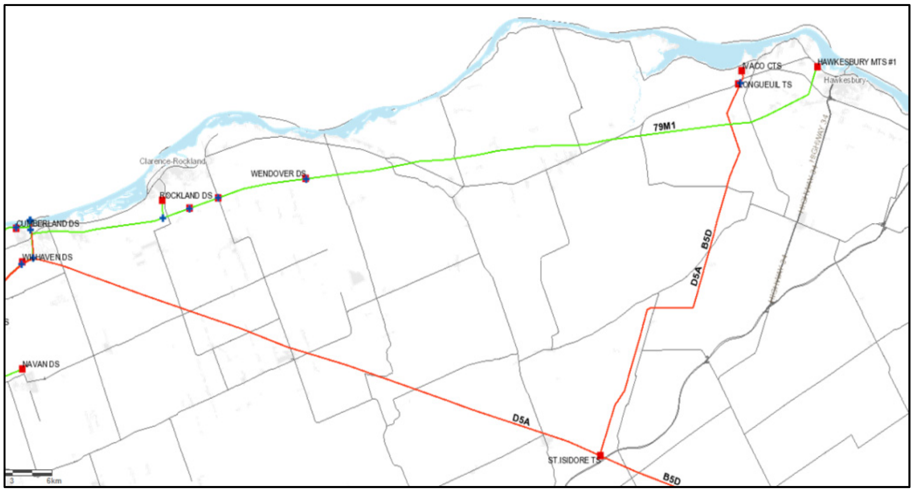

Figure 3-2 Outer Ottawa Sub-Region, Eastern Area

The western area of the Outer Ottawa Sub-Region is served by one 230 kV and two 115 kV step-down transformer stations. Hydro One Distribution is the LDC that supplies end use customers for these stations. The area includes the following generating stations: Barrett Chute GS, Chats Falls GS and Stewartville GS with a peak generation capacity of about 450 MW.

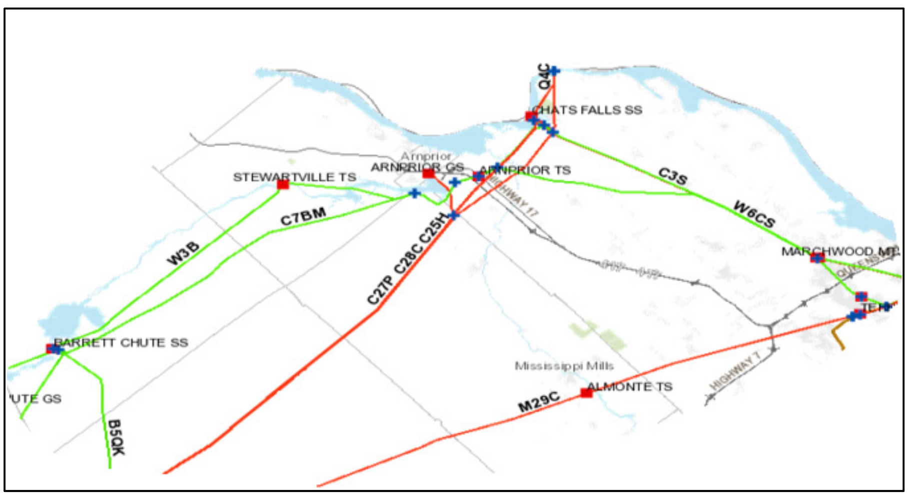

Figure 3-3 Outer Ottawa, Western Area

An electrical single line diagram for the Greater Ottawa Region facilities is shown in Figure 3-4.

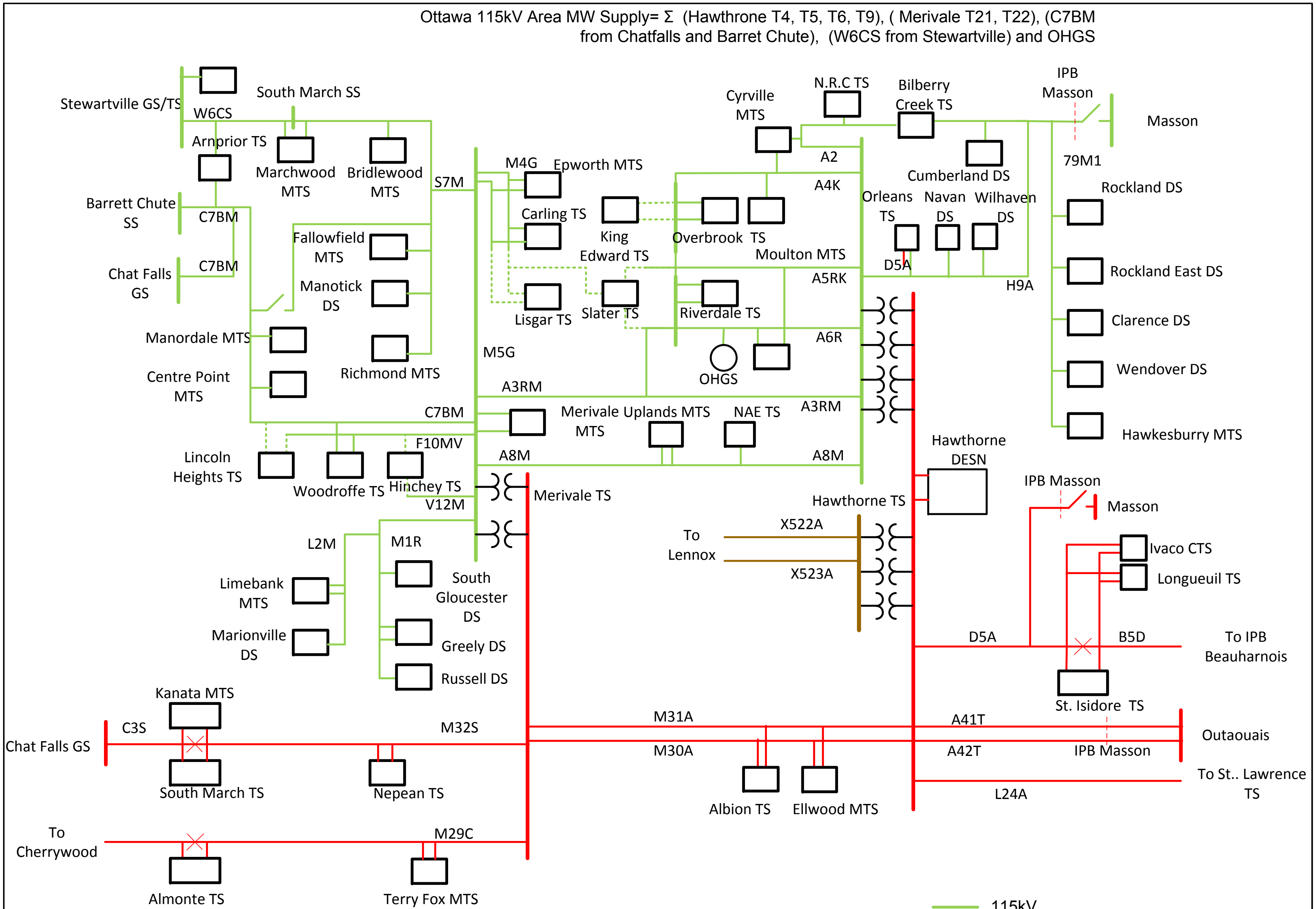

Figure 3-4 Greater Ottawa Region – Electrical Supply

115kV
230kV
500kV

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GREATER OTTAWA REGION IN GENERAL AND THE CITY OF OTTAWA IN PARTICULAR.

These projects were identified as a result of either: joint Hydro One, IESO and Hydro Ottawa planning studies to meet the needs of Hydro Ottawa or Hydro One Distribution; and/or, to meet provincial government policies. A brief listing of the completed projects over the last 10 years is given below:

- Hawthorne TS x Gamble Junction double circuit 230 kV Overhead line (2008) – the single 115 kV circuit H9A was rebuilt as a two circuit 230 kV tower line with increased capacity. Connect Cyrville MTS (2008) – connected new Hydro Ottawa owned Cyrville TS to 115 kV circuits A4K and A2.
- Hawthorne TS x Outaouais TS double circuit 230 kV line (2009) – built to provide up to 1250MW of transfer capability with Hydro Quebec as part of the new HVDC interconnection.
- Connect Ellwood MTS (2012) – connected new Hydro Ottawa owned Ellwood TS to 230 kV circuits M30A and M31A.
- Connect Terry Fox MTS (2013) – connected new Hydro Ottawa owned Terry Fox MTS to 230 kV circuit M29C.
- Hawthorne TS 115 kV switchyard Upgrade (2014) – replaced 115 kV breakers with inadequate short circuit capability with new breakers of higher short circuit capability. This work improved system reliability by allowing 115kV switchyards to be operated with bus tie closed. This work also facilitated incorporation of DG in the Ottawa area.
- Build new Orleans TS (2015) – built a new step-down transformer station in East Ottawa supplied from 230 kV circuit D5A and 115 kV circuits H9A. This station will provide additional load meeting capability to meet Hydro One Distribution and Hydro Ottawa requirements. It will also provide improved reliability for Hydro One Distribution customers in the Orleans-Cumberland area.
- Hinchey TS (2015) – Connect idle winding of transformer T1/T2 to new Hydro Ottawa metalclad switchgear.

The following projects are currently underway:

- Add 230 kV inline breaker on 230 kV circuit M29C at Almonte TS (2015) – to improve reliability of supply for Almonte TS and Terry Fox MTS.
- Replace 45/75 MVA, 115/13.2 kV step down transformers with new 60/100 MVA, 115/13.2 kV at Overbrook TS (2017) – the existing transformers are at end-of-life and the new replacement transformers have a higher rated capacity and will provide additional load meeting capability.

- Replace 225 MVA, 230/115 kV autotransformers T5 and T6 at Hawthorne TS with new 250 MVA, 230/115 kV autotransformers (2018) – the existing transformers have inadequate capacity and were identified and recommended for replacement during the IRRP phase for the Ottawa Sub-Region [1].
- Replace 50/83 MVA, 230/44 kV step down transformers with new 75/125 MVA, 230/44 kV units at Hawthorne TS (2019) – the existing transformers are at end-of-life and the new replacement transformers have a higher rated capacity and will provide additional load meeting capability.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Ottawa Area is forecast to increase at an average rate of approximately 2.25% annually up to 2020, at 0.96% between 2020 and 2025 and at 0.45% beyond 2025. The growth rate varies across the Region with most of the growth concentrated in the Ottawa Sub-region.

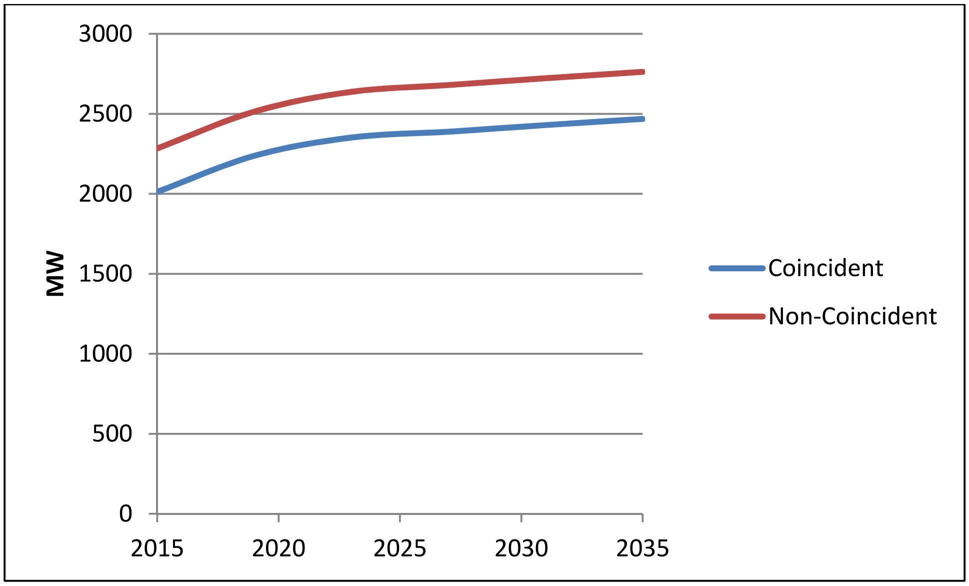

Figure 5-1 Greater Ottawa Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Greater Ottawa Region extreme weather peak summer coincident and non-coincident load forecast. The coincident forecast represents the sum of the peak load at the time of the region's peak load and represents loads that would be seen by the autotransformer stations and is used to determine the need for additional auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for stations and line capacity. Coincident and Non-coincident load forecasts for the individual stations in the Greater Ottawa Region are given in Appendix A.

The RIP load forecast was developed as follows:

- RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IESO's 2015 IRRP for the Ottawa Sub-Region[1] and Hydro One's 2014 NA [2] was still valid and there were no changes.
- The station coincident loads used in the RIP are as given in the IRRP for Ottawa Sub-Region and NA for the Outer Ottawa Sub-Region. The coincident loading is used for evaluating the adequacy of bulk transmission circuits and the 230/115kV autotransformers.

- Stations non-coincident load forecast was developed using the summer 2015 actual peak load adjusted for extreme weather and applying the station net growth rates as identified in the IRRP and NA. The non-coincident forecast is used to determine adequacy of station capacity. The net growth rate accounts for CDM measures and connected DG. Details on the CDM and connected DG are provided in the IRRP [1] and NA for Ottawa Sub-Region [2] and are not repeated here.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GREATER OTTAWA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM. NO LONG TERM NEEDS HAVE BEEN IDENTIFIED.

Within the current regional planning cycle two regional assessments have been conducted for the Greater Ottawa Region. The April 2015 Ottawa Sub-Region IRRP report [1] was prepared by the IESO in conjunction with Hydro One and Hydro Ottawa. The July 2014 Outer Ottawa Sub-Region NA report [2] was prepared by Hydro One and considered the remainder of the Greater Ottawa region.

The IRRP [1] and NA [2] planning assessments identified a number of regional needs to meet the area forecast load demand over the near to mid-term between 2015 and 2025. These regional needs are summarized in Table 6.1 and include needs for which work is already underway and/or being addressed by an LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Greater Ottawa Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Near and Mid-Term Regional Needs

Type	Section	Needs	Timing(4)
Needs identified in IRRP [1] and NA [2]			
230/115kV Transformation Capacity	7.1	Hawthorne TS T5 and T6 – LTR(1) exceeded	2018(2)
	7.2.1	Merivale TS T22 - LTR(1) exceeded	2019
Transmission Circuit Capacity	7.2.2	S7M Circuit – Capacity	2019 and 2026
	7.3	A4K Circuit - Capacity	2019(2)
Station Capacity	7.4	Center 115kV Area - Capacity	2017-2021(3)
	7.5	Hawthorne TS T7 and T8 – LTR(1) exceeded	2019
	7.2.2	South West Area - Capacity	2020
	7.6	Bilberry Creek TS - Refurbishment	2023
Supply Security, Reliability and Restoration	7.7	Almonte TS/Terry Fox MTS - Reliability	2015
	7.8	Orleans TS - Reliability	No plan recommended(5)
	7.9	B5D+D5A Circuits – Restoration	No plan recommended(5)
	7.10	Load Loss for S7M Contingency	No plan recommended(5)
Voltage Regulation	7.11	79M1 Circuit – Voltage Regulation	2023
	7.12	Stewartville TS – Voltage Regulation	No plan recommended(5)
	7.13	Almonte TS/Terry Fox MTS –Voltage Regulation	No plan recommended(5)
	7.14	Almonte TS – Low Power Factor	No plan recommended(5)
Additional Needs identified in RIP			
	7.2.1	Merivale TS T22 and Hawthorne TS T9 – Continuous ratings exceeded	2024/25
	7.4.2.4	King Edward TS – Capacity	2021

(1) LTR – Limited time ratings to accommodate emergency loading for a short time under contingency conditions
(2) Projects have been initiated.
(3) Miscellaneous stations. Some are already in execution.
(4) Timing shows the proposed in service date for project underway, and the need date for the projects not yet started.
(5) Review did not recommend plan for mitigation. Please see the need details in Section 7.

6.1 500 and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the Greater Ottawa Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and to the Hydro Quebec transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. These circuits are as follows (refer to Figure 3-4):

1. Hawthorne TS to Merivale TS 230 kV transmission circuits M30A/M31A – supply Albion TS and Ellwood TS.
2. Hawthorne TS to Cornwall 230 kV transmission circuits D5A/B5D/B31L – supply Orleans TS, St. Isidore TS and Longueuil TS. Also connects to Hydro Quebec at Beauharnois Station and to Lievre Power at Masson GS.
3. Merivale TS to Chats Falls 230 kV transmission circuits M32S/C3S – supply Nepean TS, South March TS and Kanata MTS
4. Merivale TS x Cherrywood TS 230 kV transmission circuits E29C/E34M (M29C) – supply Terry Fox MTS and Almonte TS.

Based on current forecast station loadings and bulk transfers, the M30A/M31A circuits will require reinforcement by 2020. The M30A/M31A upgrade will be addressed by Hydro One based on the recommendation stemming from an IESO Bulk System Planning study [6]. All other 230 kV circuits are expected to be adequate over the study period.

6.2 230/115 kV Transformation Facilities

Almost sixty percent of the Region load is supplied from the 115 kV transmission system. The primary source of 115 kV supply is from 230/115 kV autotransformers at Hawthorne TS and Merivale TS. Additional support is provided from 115 kV generation at Barrett Chute GS, Stewartville GS, part of Chats Falls GS, and the Ottawa Health Science NUG and the Ottawa River generation at Chaudière. Support from DG and CDM was considered as part of the load forecast.

Table 6-2 summarizes the results of the adequacy studies and gives the need dates for reinforcement of the 230/115 kV autotransformer facilities at Hawthorne TS and Merivale TS. Assuming no change in the system configuration, the forecasted loading will result in the Limited Time Rating ("LTR") of the Merivale autotransformer being exceeded by 2019 and the continuous rating of the Merivale and Hawthorne autotransformers by 2024/25.

The need dates are sensitive to the availability of hydraulic generation from Barrett Chute GS, Stewartville GS and Chats Falls GS and are based on 98% dependable generation availability as per ORTAC criteria. This corresponds to about 18 MW of available generation. A higher level of generator output from these stations would defer the need dates.

The need dates assume that the Hawthorne TS 225 MVA, 230/115 kV autotransformers T5 and T6 have been replaced with new 250 MVA units. The T5 and T6 replacement work is underway and is therefore not identified in the table below.

Table 6-2 Adequacy of 230/115 kV Autotransformer Facilities

Overloaded Facilities	2015 MVA Loading	MVA Load Meeting Capability	Limiting Contingency	Need Date
Merivale TS 230/115kV autotransformer T22	261	312(1)	T21	2019
Merivale TS 230/115kV autotransformer T21	182	250	(2)	2024
Hawthorne TS 230/115kV autotransformer T9	189	250	(2)	2025

(1) Limited time rating exceeded.

(2) Continuous rating exceeded with all elements in service based on existing system configuration

6.3 115 kV Transmission Facilities

The Greater Ottawa Region 115 kV transmission facilities can be divided in five main sections: Please see Figure 3-4 for the single line diagram.

1. Hawthorne 115 kV Center – has four circuits A3RM, A4K, A5RK and A6R. Reinforcement is required for the A4K circuit as a loss of the A5RK circuit would result in the loading exceeding the rating on the A4K circuit between Hawthorne TS and Moulton MTS (for details see Section 7.3).
2. Hawthorne 115 kV East – has two circuits A2 and H9A/79M1. These are expected to be adequate over the study period.
3. Merivale 115 kV Center – has two circuits M4G and M5G. These are expected to be adequate over the study period.
4. Merivale 115 kV West – has five circuits C7BM, F10MV, S7M, V12M and W6CS. Upgrading is required of the S7M tap to Fallowfield TS since forecasted loading will exceed circuit continuous rating (for details see section 7.4)
5. Merivale 115 kV South – has two circuits L2M and M1R. These circuits are adequate for the study period.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Adequacy of 115 kV Circuits

Corridor	Section	Overloaded Circuit	Rating (A)	Contingency	2015 Loading (A)	Need Date
1. Hawthorne TS x Blackburn Jct. x Overbrook TS	Hawthorne TS x Moulton TS	A4K	1070	A5RK	1006	2017
4. S7M tap to Fallowfield MTS	STR R14-R15 x Fallowfield Jct.(2)	S7M	590	All facilities in-service(1)	278	2024

(1) Continuous rating exceeded.
(2) Please see Figure 7-4.

6.4 Step-Down Transformation Facilities

There are a total of fifty-two step-down transmission connected transformer stations in the Greater Ottawa Region. The stations have been grouped based on the geographical area and supply configuration. The non-coincident station loading in each area and the associated station capacity and need date for relief is provided in Table 6-4 below. As shown areas requiring additional transformation capacity are the Center 115kV area, the South West 115kV area and the South 115kV area. Table 6-5 shows the non-coincident station loads for all areas which are adequate over the 2015-2025 study period. Details of the areas and associated stations are given in Appendix B.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
Center 115	569(1)	516	2018
South West 115	70	60	2019
South 115	182	151	2024

(1) With Overbrook TS 45/75 MVA transformers replaced with larger 60/100 MVA units.

Table 6-5 Adequacy of Step-Down Transformer Stations – Areas Adequate

Area/Supply	Capacity (MW)	2015 Loading (MW)	2025 Loading (MW)
East 115	340	231	229
West 115	504	351	425
Center 230/13.2kV	147	121	126
Center 230/44kV	153(1)	103	136
West 230	397	382	389
Outer East 115	80	56	62
Outer West 115	106	83	96
Outer East 230	149(2)	92	90
Outer West 230	100	48	45

(1) With Hawthorne TS 50/83 MVA transformers replaced with larger 75/125 MVA size units.
(2) Includes Longueuil TS and St Isidore TS load.

7. REGIONAL PLANS

This section discusses needs, presents wires alternatives and the current preferred wires solution for addressing the electrical supply needs for the Greater Ottawa Region. These needs are listed in table 6-1 and include needs previously identified in the IRRP for the Ottawa Sub-Region [1] and the NA for the Outer Ottawa Sub-Region [2] as well as the adequacy assessment carried out as part of the current RIP report.

7.1 Hawthorne Autotransformer T5 and T6

7.1.1 Description

Hawthorne TS is a major supply point for the city of Ottawa (Figure 7 -1). The station has four 230kV/115 kV autotransformers. Two of these autotransformers, T5 and T6, have lower ratings, with 225 MVA continuous and 256 MVA LTR, respectively. Under contingency conditions, i.e. one of the autotransformers out of service, the ratings of these two autotransformers are exceeded and this limits the supply to the 115 kV network from the 230 kV system. As the load continues to grow on the 115 kV network, this limitation needs to be addressed. This had been identified as a near term need in the Ottawa Sub-Region IRRP [1] and was included in the Ontario Power Authority's ("OPA", now part of IESO) June 2014 letter to Hydro One [5].

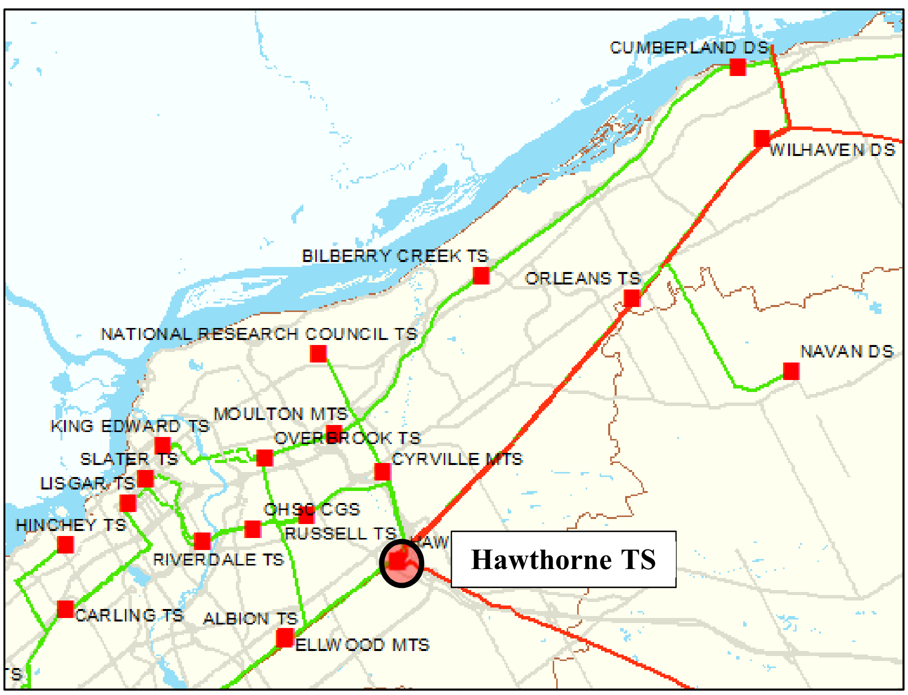

Figure 7-1 Hawthorne TS

7.1.2 Recommended Plan and Current Status

Hydro One has established a project to replace autotransformers T5 and T6 with new higher rated autotransformers. These autotransformers will have an LTR of at least 350 MVA. This investment will provide additional capacity and meet the needs of the area. It is expected that the project will be completed in 2018.

The cost of this project is expected to be $15.7 million. The project will be a transmission pool investment as the autotransformers provide supply to all customers in the Greater Ottawa Region.

7.2 Autotransformation Capacity and South West Area Station Capacity

7.2.1 Merivale TS Autotransformers T21 and T22/Hawthorne Autotransformer T9

Merivale TS has two 230 kV/115 kV autotransformers with an LTR station capacity of 312 MVA. The station is supplied from Hawthorne TS and from generators located west of Ottawa, along the Ottawa River and the Madawaska River. Merivale TS is shown in Figure 7-2.

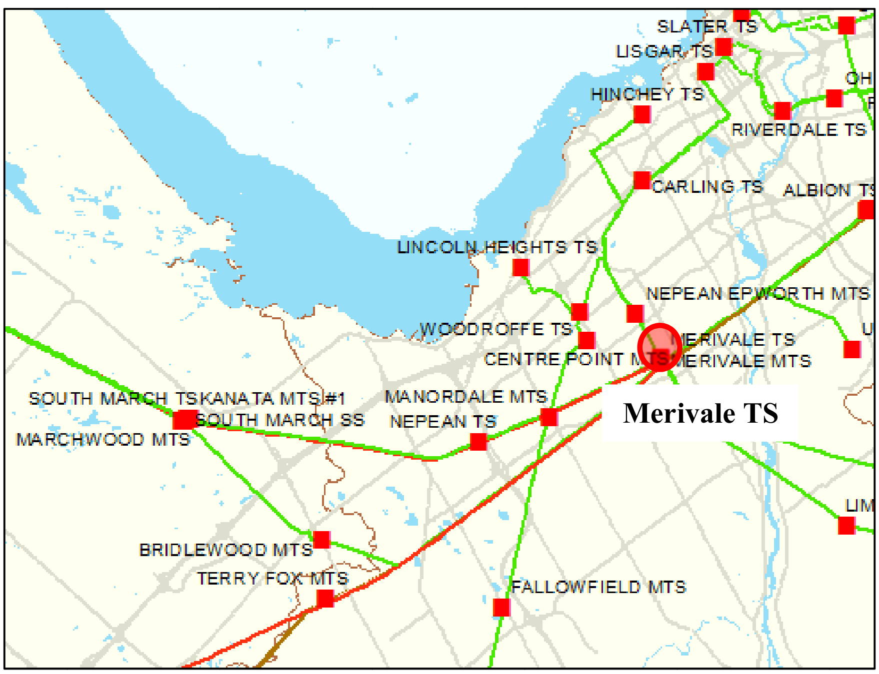

Figure 7-2 Merivale TS

The expected load growth provided by the LDCs and the minimum hydro generation assumption described in Section 6.2 causes the station capacity to be exceeded under contingency conditions by 2019. In addition, it is expected that autotransformers at Merivale TS and Hawthorne TS will reach their continuous loading limits of 250 MVA by 2024 and 2025. The exact timing of the autotransformer needs is dependent on the following factors:

- The South West area load forecast includes a proposed connection of a single large load increase coming into service in 2019.
- The need date is sensitive to generation at Stewartville GS, Barrett Chute GS and Chats Falls GS as its effect is to reduce the flow through the autotransformers.
- A potential solution to the need for additional supply capacity in the South West Area is a new 230 kV supply station which would remove some of the demand growth and existing load from the 115 kV network (see Section 7.2.2 for a complete description of this issue). This work would also help defer the need for additional autotransformer capacity at Merivale TS.

In order to address the Merivale TS autotransformer capacity concerns, additional 230/115 kV transformation capacity or load transfer from the 115 kV to the 230 kV system is required.

The provision of additional transformation capacity requires replacing the Merivale TS T22 autotransformer with a newer higher rated transformer in 2019 and adding a third autotransformer at the station in 2024. Alternatively a third transformer can be added at Merivale TS by 2019. To meet the required 2019 need date a decision on the autotransformer work is required by summer 2016.

Transferring load to the 230kV system requires establishing a new 230/27.6kV transformer station in the South West area to pick up some of the existing load and all of the new load growth. This is described in the following section.

7.2.2 Supply to South West Area – Line and Station Capacity

The South West area is served by Fallowfield MTS, Richmond MTS and Manotick DS connected to the 115kV circuit S7M out of Merivale TS. Load demand in the area is expected to increase by 52 MW in the next 10 years and both the line and station capacity are forecast to be exceeded by 2019.

The line limitation was identified in the OPA's June 2014 letter [5] to Hydro One. A section of the S7M circuit between the main line at STR R14-R15 JCT and Fallowfield Junction (see Figure 7-3 below) had a capacity of 420A. Hydro One review of the line capacity showed that the line rating was limited to respect safety clearances due to an underbuilt distribution feeder at Fallowfield MTS. This issue has been resolved with Hydro Ottawa carrying out the necessary work to lower the distribution feeder and increase the transmission line clearance. The line rating has been increased to 590A and is now adequate to meet forecast load until 2026.

Additional transformation capacity is required in the South West Area and both Fallowfield MTS and Richmond DS require load relief. Hydro Ottawa is planning for a capacity increase at Richmond DS and potentially a new station to relieve Fallowfield MTS in the Barrhaven area.

The IESO has initiated a public engagement process to gather community input for a preferred supply plan for the area including consideration of the potential for incremental CDM and DG resources and/or transmission expansion in the form of a new TS. The IRRP [1] recommended that given the required timeline, it would be beneficial for early transmission planning options to be started in parallel to the engagement process, prior to completing the integrated plan.

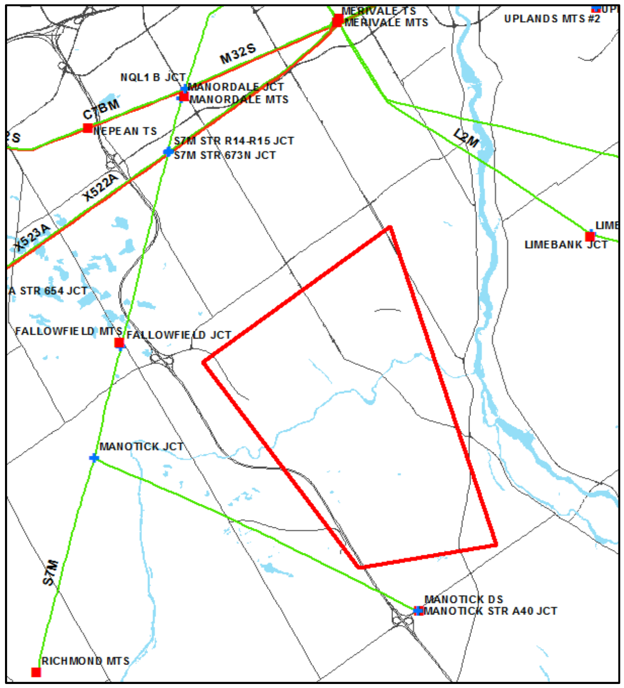

Figure 7-3 South West Area

At a high level, there are two main wire options to supply the South West area:

a) 115kV Option: Build a new 115/27.6kV transformer station and reinforce the existing 115 kV supply
b) 230kV option: Build a new 230/27.6kV transformer station and provide a new 230 kV transmission supply to the area.

The main advantage of the 115 kV option is that it defers the need for new transmission line until 2026. It however has a number of disadvantages: (a) loading will continue to increase on the 115kV system necessitating additional transformation capacity a Merivale TS by 2019 and Hawthorne TS by 2025, (b) all area stations remain on a single line supply until new transmission is built, and (c) the new 115 kV supply will provide less incremental capacity for the future.

The 230 kV option has the advantage of providing relief for the 230/115 kV autotransformers at Merivale TS and Hawthorne TS as well as provide more capacity to serve the area load. It also improves the area reliability by providing a second source of supply. The disadvantage is that transmission reinforcement will be required by 2019 and decision needs to be made as soon as possible.

The RIP has considered two options as examples for providing 230 kV supply to the area. Both examples consider building new double circuit 230 kV lines on existing Right of Way ("ROW") in accordance with the provincial government policy to maximize ROW use. The two options are described below (also refer to Figure 7-3).

- *S7M Based Option - Rebuild S7M as a double circuit 230 kV line.*

  This option would require rebuilding the existing single circuit115 kV circuit S7M tap to Fallowfield MTS as a new double circuit 230 kV line. The line would extend from the S7M STR R14-R15 JCT (on the main line) to Manotick Jct. Depending on the station location, a part of S7M from Manotick JCT to Manotick DS would also have to be rebuilt for a total line rebuild of up to 15.5 km. One circuit would be operated at 115 kV and continue to supply Fallowfield MTS, Richmond DS and Manotick DS. The other circuit would be tapped off the 230 kV circuit M29C which is adjacent to S7M at STR R14-R15 JCT and will be used to supply the new Hydro Ottawa station. This option may require sections of the existing ROW to be widened to accommodate the 230 kV circuits. Additional real estate rights will have to be obtained. EA and OEB Leave to Construct (Section 92) approvals will also be required.

- *L2M Based Option - Rebuild L2M as a double circuit 230 kV Line*

  This option would require rebuilding the existing 115 kV circuit L2M from Merivale TS to past Limebank MTS as a new double circuit 230 kV line. This section of the line would be constructed using the existing L2M ROW for a distance of 8.5 km. A new 6-8 km long ROW would need to be acquired going west from the L2M ROW to bring the transmission line to the load area, crossing the Rideau River. One circuit on the new line would remain L2M and be operated at 115 kV. The other circuit would connect to circuit M32S at Merivale TS and be operated at 230 kV. The new station will be supplied from the 230 kV circuit.

7.2.3 Recommended Plan and Current Status

The needs for autotransformation capacity and a new station in south west are interrelated. Further analysis is required to determine the impact of the 230 kV supply options for the new south west station on the Merivale TS and Hawthorne TS autotransformers. The planning assessment will consider whether a 115kV supply to the new station in combination with the addition of an autotransformer at Merivale is more cost effective than a 230kV supply.

The IESO is currently carrying out community engagement activities in the Ottawa region. The Working Group will be discussing the supply options for the South West area in conjunction with the autotransformer upgrade work at Merivale TS and expect to recommend a preferred plan for the area by summer 2016.

7.3 115 kV Transmission Circuit A4K Supply Capacity

7.3.1 Description

Circuit A4K is a 115 kV circuit supplying four downtown stations: Overbrook TS, King Edward TS, Cyrville MTS and Moulton MTS. Loading on the A4K this circuit can exceed its rating under peak load conditions for loss of 115 kV circuit A5RK. This need was identified as a near term need in the Ottawa Sub-Region IRRP [1] and included in the OPA's June 2014 letter to Hydro One [5]. In this letter, the preferred plan to relieve circuit A4K is outlined. This plan consists of rebuilding an approximately 2 km long section of single circuit 115 kV circuit A5RK between Overbrook TS to Riverdale Jct. as a double circuit line (see Figure 7-4). One of the circuits would remain A5RK and the other would be tapped to circuit A6R. Overbrook TS will be reconfigured to be supplied from circuits A5RK/A6R instead A4K/A5RK. This reconfiguration would remove Overbrook TS load from 115 kV circuit A4K and eliminate the overloading on A4K for the loss of A5RK.

7.3.2 Current Status

Hydro One has initiated the development work for this line rebuild. The project is currently in the engineering and estimating phase. The project is not expected to require Leave to Construct (Section 92) approval, but will require Environmental Assessment ("EA") approvals.

The project is expected to be in service by spring 2019 and preliminary estimates suggest the cost to be approximately $9 million to $11 million. This work will be part of the Line Connection pool and costs will be recovered from the rate revenue and/or customer capital contribution in accordance with the TSC. As a result, the LDC may be required to make a capital contribution.

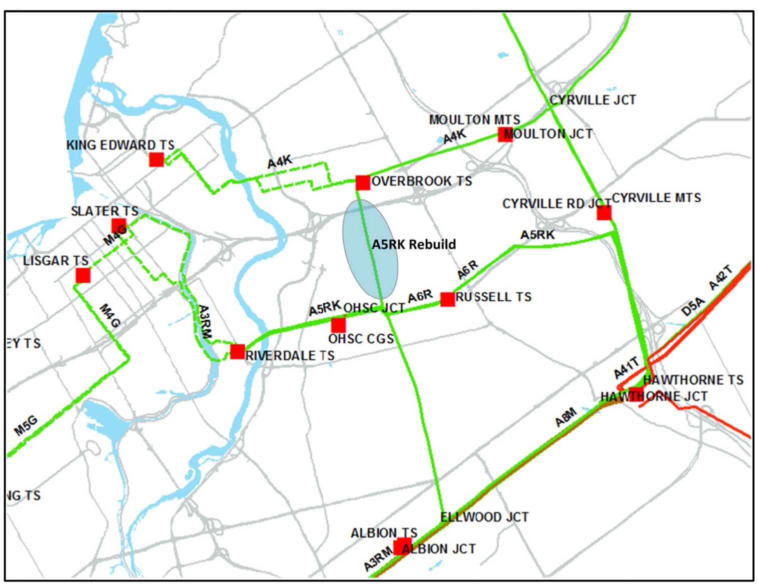

Figure 7-4 Option to Rebuild A5RK as Double-Circuit 115 kV Line

In the interim, Hydro One and Hydro Ottawa have operational mitigating measures to manage the overload on 115 kV circuit A4K if it becomes of concern before Hydro One has completed the line rebuild work. These measures include the transfer of Cyrville MTS to single supply from circuit A2 only by opening the A4K breaker at Cyrville MTS, and the transfer of some load from Moulton MTS to other stations in the area.

7.4 Station Capacity – Ottawa Centre 115 kV Area

7.4.1 Description

The Ottawa Center 115 kV area covers the City of Ottawa downtown district and extends from the Ottawa River in the north to Smyth Road in the south as shown in Figure 7-5 below. It is served by six 115/13.2 kV step-down transformer stations – King Edward TS, Lisgar TS, Overbrook TS, Riverdale TS, Russell TS and Slater TS. Most of the area stations are at or near capacity. Even with the Overbrook upgrade work now underway additional load meeting capability is forecast to be required by 2018 as shown in Table 6.3.

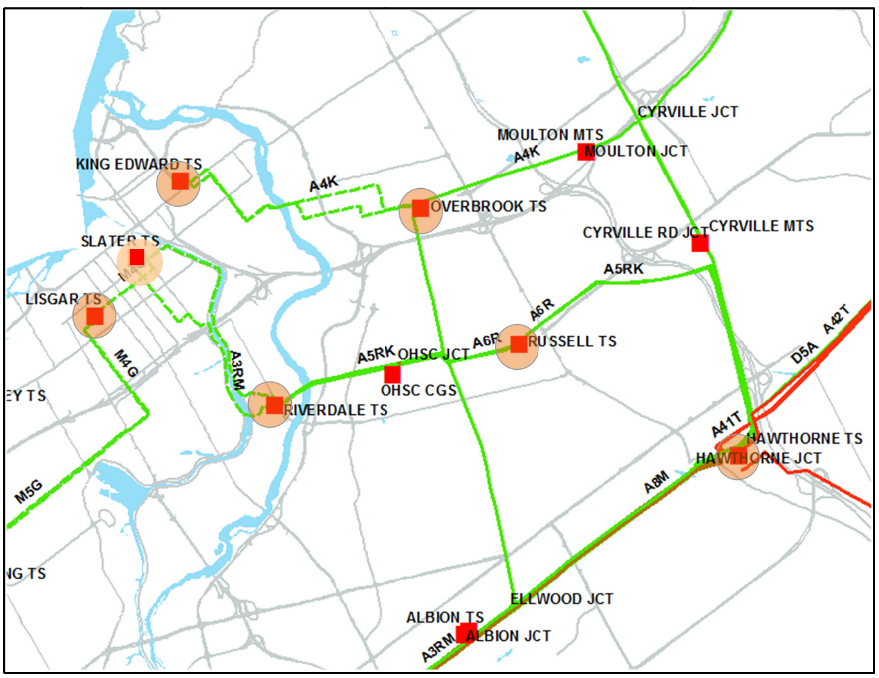

Figure 7-5 Downtown Ottawa Stations

7.4.2 Recommended Plan and Current Status

The existing step-down stations in the area are equipped with older 45/75 MVA transformers which have a LTR of between 70-80 MW. The preferred alternative to provide additional transformation capacity in the area is to replace these units with larger sized 100 MVA units where possible with an LTR of up to 130 MW.

During this regional planning cycle, the Working Group participants agreed to take advantage of transformer replacements necessitated by end-of-life considerations as this was the lowest cost and most practical option to provide additional capacity. The alternative of building a new station to provide capacity was ruled out because of the high cost and the difficulty in acquiring an appropriate site.

Upgrade of the end of life transformers at Overbrook TS is currently underway. In the future, the Working Group will continue to look for opportunities to upgrade based on end-of-life considerations of transformers. Hydro One will keep the Working Group informed of these opportunities. In addition, load transfers are also recommended to utilize available capacity at adjacent stations.

7.4.2.1 Russell TS and Riverdale TS

The loading on these stations will be kept within limits by Hydro Ottawa building feeder ties to transfer excess loads to other area stations. This will keep the loading on the transformers at these stations within their rating. A high level cost estimate of Hydro Ottawa's distribution work is $2 million.

7.4.2.2 Overbrook TS

Hydro One had identified that the step-down transformers at Overbrook TS were approaching end-of-life and consideration was therefore given to upgrading the transformers at the station. Accordingly Overbrook TS transformers are being replaced with larger sized units which will increase the station capacity from 72 MW to 130 MW. The work is underway and planned to be completed in Q2 2018. The incremental cost of upgrading to larger transformers is estimated to be $1.1 million. The cost of upgrading is expected to be recovered from incremental rate revenue in accordance with the TSC. Based on current forecast Hydro Ottawa is not expected to pay any capital contribution for this project.

7.4.2.3 Lisgar TS

Lisgar TS has two 75 MVA transformers. To meet the forecast load requirement additional transformation capacity is required in the Central 115kV area. Hydro Ottawa has therefore asked that the Lisgar TS transformers be replaced with larger 100 MVA units. The cost of the work is estimated to be about $14 million and will be recovered from rate revenue and customer capital contribution in accordance with the TSC. The target in-service date is Q4 2017.

7.4.2.4 King Edward TS

The capacity at King Edward TS is 71 MW. By replacing the limiting transformer T4 and additional low voltage ("LV") components such as circuit breakers and cable, a higher capacity of up to 130 MW can be achieved at King Edward TS.

Considering the Overbrook TS and Lisgar TS upgrades, adequate capacity will be available in the Center area until 2021. After discussion with Hydro Ottawa, the King Edward TS transformer upgrade work is tentatively scheduled for an in-service date of 2021. The project cost is estimated to be about $12M and will be recovered from rate revenue and customer capital contribution in accordance with the TSC.

7.5 Station Capacity - Hawthorne TS 44kV

Hawthorne TS has two 50/83 MVA, 230/44kV transformers with an LTR of 89 MW. Additional 44kV capacity is required at the station. Hydro One identified that the step- down transformers at Hawthorne TS were approaching end-of-life and needed to be replaced. The lowest cost alternative to provide this additional capacity was to take advantage of the transformer replacement work and install larger 75/125 MVA transformers with an LTR of 153 MW. This work is currently underway and planned to be completed by summer 2019.

Additional 44kV feeder positions will be required to utilize this increased capacity. These feeders will be added as required.

The incremental cost of upgrading to larger transformers is estimated to be approximately $1.1 million. Feeder position costs have not been estimated at this time. Incremental transformer costs and the feeder costs will be recovered in accordance with the TSC. Based on the current forecast Hydro Ottawa is not expected to pay any capital contribution for this project.

7.6 Bilberry Creek TS End of Life

7.6.1 Description

Bilberry Creek TS is a 115/27.6 kV step-down transformer in East Ottawa, supplying up to 85 MW of load customers to both Hydro Ottawa and Hydro One Distribution. The station was built in 1964 and a number of its key components have been identified for replacement by Hydro One. This station's refurbishment work is to be complete by 2023. A decision will be required by 2020 on whether to refurbish the station and keep the load on the 115 kV system or to retire the station and move the load over to the 230 kV system by supplying it from the newly built Orleans TS.

A Local Plan [3] carried out by Hydro One shows that the two options are similar in costs. The retirement option however, may be more attractive particularly if 115 kV load growth rate is high in the Ottawa Center area. The retirement option will reduce the loading of the 230 kV/115 kV autotransformers at Hawthorne TS and Merivale TS and make it available for the Ottawa Center 115 kV load. Figure 7-6 shows the area under consideration.

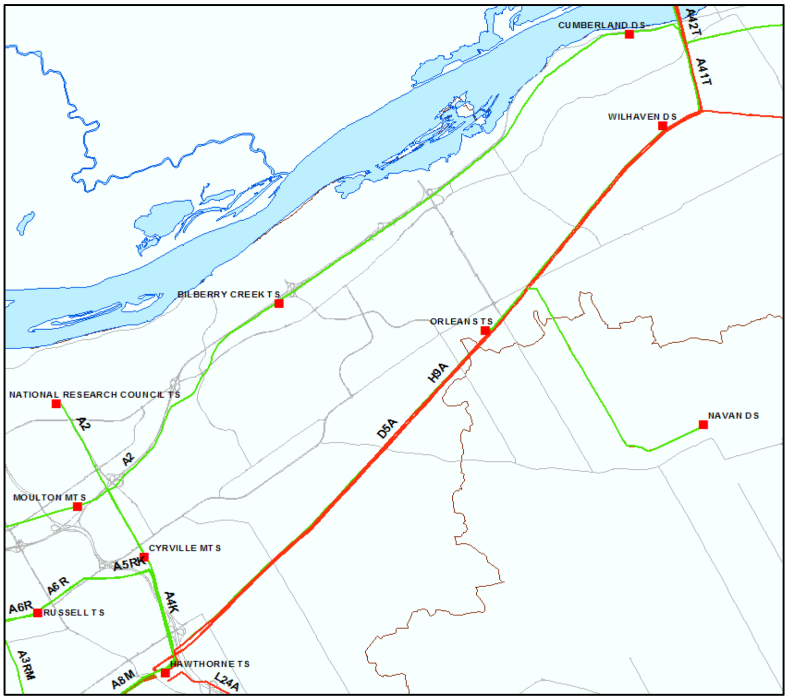

Figure 7-6 Bilberry Creek TS and the East Ottawa Area

7.6.2 Recommended Plan and Current Status

The two alternatives are very similar in cost and each has its own pros and cons. The refurbishment option minimizes work on the distribution system, but leaves the load on the 115kV system and with lower overall capacity to meet long term growth. The retirement option moves Bilberry Creek load to the 230kV system with higher long term load meeting capability but involves relocating distribution feeders from Bilberry Creek TS to Orleans TS.

The Working Group has recommended that a decision on Bilberry Creek refurbishment be deferred to the next regional planning cycle as there is still sufficient time to make an investment decision.

7.7 Almonte TS and Terry Fox TS Reliability

7.7.1 Description

Almonte TS and Terry Fox MTS are supplied from the 319 km long 230kV circuit M29C, see Figure 7-7. Due to the long length of the line the exposure to outages is high. The line has averaged approximately 6-7 interruptions per year over the last 10 years. With Terry Fox MTS coming into service in 2013, concerns were expressed about the number of outages that would be seen by the station. This issue was identified in the Ottawa Sub-Region IRRP [1] and the OPA's June 2014 letter [5].

7.7.2 Recommended Plan and Current Status

Hydro One had initiated a project in 2012 to install a 230 kV circuit breaker at Almonte TS. This breaker would sectionalize the M29C line into two sections: E29C – 281 km Cherrywood TS to Almonte TS; and E34M – 38 km Almonte TS to Merivale TS. This breaker will help with the number of interruptions at Almonte TS and Terry Fox MTS by eliminating outages due to the Almonte TS x Cherrywood section of the circuit.

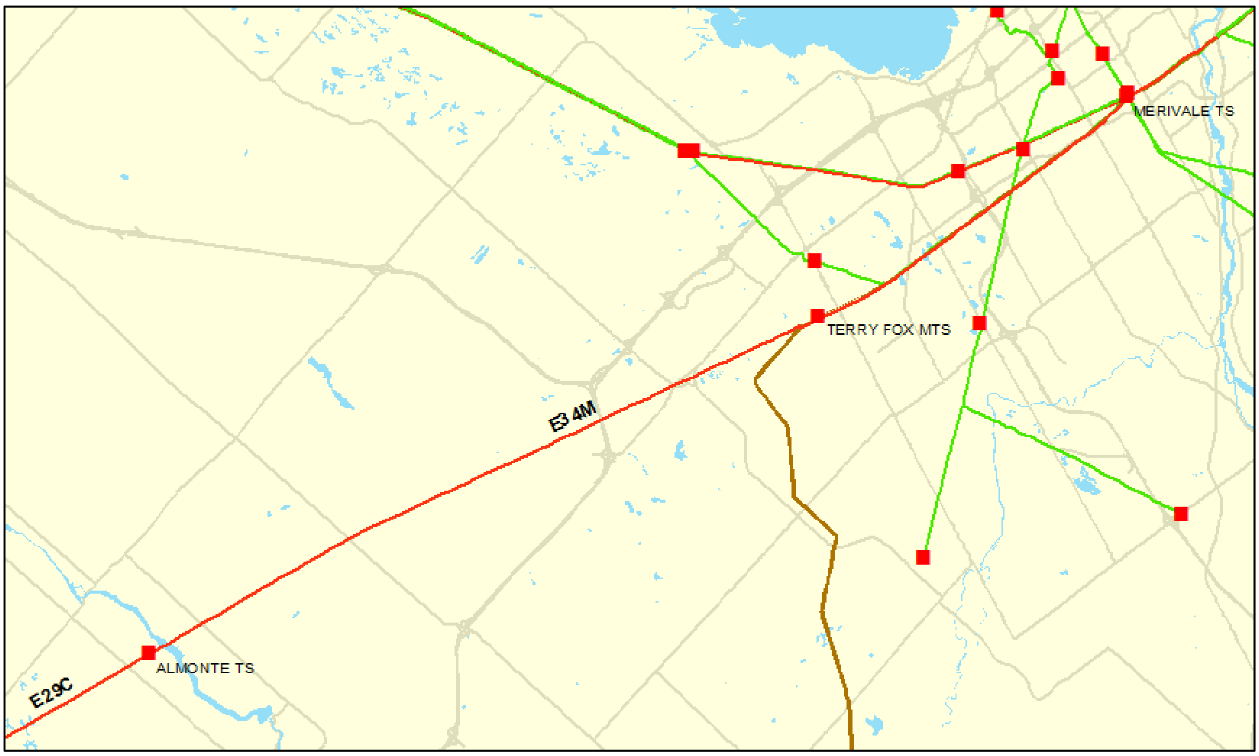

Figure 7-7 Lines E29C and E34M (M29C). In-Line Breaker at Almonte TS.

The total cost of this project is estimated to be $4.7 million and the project is scheduled to be completed by December 2015.

A second supply from Merivale TS to Terry Fox MTS was previously considered as an option to improve reliability. However it was decided to install the in-line breaker at Almonte TS since it was the cost effective and provided reliability improvement to both Almonte TS and Terry Fox MTS.

It should be noted that the Terry Fox TS is operated with the LV bus tie open. This arrangement has the disadvantage that in case of a transformer outage, the load connected to that transformer will be lost momentarily before the bus tie is closed to allow all loads to be supplied from the other side. A second supply to Terry Fox MTS can still be considered to address this issue as the load increases as part of a longer term supply plan. This will continue to be reviewed.

7.8 Orleans TS Reliability

7.8.1 Description

Orleans TS is a new station Hydro One built in East Ottawa to provide additional transformation capability and improve supply reliability for Hydro One Distribution customers connected to the 115 kV circuit H9A.

The Orleans TS is built adjacent to the double circuit H9A/D5A line about 10 km from Hawthorne TS and has one step-down transformer station supplied from 230 kV circuit D5A and the second step-down transformer supplied from the 115 kV circuit H9A. The station is operated with the LV bus tie open so as to avoid any power flow between the 230 kV and 115 kV systems through the station transformers. This arrangement has the disadvantage that in case of a circuit or transformer outage, the load connected to that circuit or transformer will be lost momentarily before the bus tie is closed to allow all loads to be supplied from the other side.

7.8.2 Recommended Plan and Current Status

Orleans TS has greatly improved the reliability of customers previous supplied from Wilhaven DS and Navan DS connected to 115kV circuit H9A. The customers experienced sustained interruptions every time circuit H9A had an outage. With the Orleans TS LV bus tie arrangement customer are exposed to a momentary interruption only as the load is picked up by closing the bus tie. This arrangement was accepted as a cost effective alternative to building 10 km of transmission line between Hawthorne TS and Orleans TS to provide a dual supply to Orleans TS.

Depending on the decision taken for Bilberry Creek TS described in section 7.6, Orleans TS could be converted to a 230 kV station and the LV bus tie closed. This option would be preferred if Bilberry Creek TS is recommended to be retired. If Bilberry Creek TS is refurbished then the plan will see Orleans TS continued operation with two different voltage supplies.

The Working Group recommendation is to monitor the performance of Orleans TS to see if mitigation measures are warranted. The Working Group will further review this issue in the next regional planning cycle as part of the Bilberry TS retirement study. No further action is required at this time.

7.9 Load Restoration for the Loss of B5D/D5A

7.9.1 Description and Current Status

The NA report for the Outer Ottawa Sub-Region [2] identified that the combined loss of circuits D5A and B5D would result in a load loss of up to 174 MW. The stations considered in this analysis are St Isidore TS, Longueil TS, and Ivaco CTS. Orleans TS is also supplied by D5A however; its second supply is H9A and is not considered for the combined loss of D5A/B5D. As indicated in ORTAC, any load lost above 150 MW must be restored within 4 hours and all load be restored within 8 hours.

A LP report [4] carried out by Hydro One shows that historically, the coincidental occurrence of forced sustained outages of B5D and D5A are rare and in all cases one of the circuits was restored in less than 4 hours as per ORTAC. The report concludes that no further action is required at this time.

7.10 Load Loss for S7M Contingency

7.10.1 Description and Current Status

Circuit S7M is the single supply for the following stations: Bridlewood MTS, Fallowfield MTS, Manotick DS, and Richmond DS. The combined load at these four stations is expected to exceed 150 MW by 2022. The ORTAC requires that not more than 150MW of load may be interrupted by configuration. However, given that the 150 MW limit is anticipated in the long term, no action is required at this time.

7.11 Voltage Regulation on 115kV Circuit 79M1

7.11.1 Description and Current Status

The 115 kV circuit 79M1 supplies Rockland DS, Rockland East DS, Clarence DS, Wendover DS, and Hawkesbury MTS. The NA for Outer Ottawa Sub-Region [2] identified that the voltage at Hawkesbury TS will approach operating limits under peak load and contingency conditions by 2023.

As mentioned in the Outer Ottawa Sub-Region NA report [2], Hydro One monitors the status of the network. Given the timing for this need, this will be reassessed during the next regional planning cycle.

7.12 Voltage at Stewartville TS

7.12.1 Description and Current Status

The load on the Stewartville TS is expected to increase significantly as a result of the connection of a large utility load forecasted for 2018. This load may require reactive support to help maintain the voltages within limits during peak load conditions and no generation at Stewartville GS.

A connection impact assessment will be undertaken by Hydro One as part of connecting the utility load. Any requirements to connect the load, including reactive power support, will be outlined in the document.

7.13 Voltage Drop at Terry Fox MTS for E34M open at the Merivale End

7.13.1 Description

Circuit E34M/E29C (new name for circuit M29C following the installation of a breaker at Almonte TS) is a 319 km line between Cherrywood TS in Pickering, and Merivale TS in Ottawa. If the circuit E34M (Almonte-Merivale) is open at the Merivale end, Terry Fox MTS and Almonte TS will be supplied radially by Cherrywood TS. Given the distance between the Greater Ottawa stations and Cherrywood TS, voltages are lower than acceptable limits during normal and peak load periods and only load of up to 25 MW can be supplied with acceptable voltage. The 2012 IESO System Impact Assessment ("SIA") recommended the installation of 20 MVARs of capacitor banks at Terry Fox MTS to meet a peak load of up to 48 MW.

7.13.2 Recommended Plan and Current Status

It is recommended that Hydro Ottawa install 20 MVARs of capacitor banks at Terry Fox MTS. This should be adequate for the near term.

Terry Fox MTS is part of the Ottawa Area under voltage load rejection scheme ("UVLS"). This scheme is designed to shed the station load if the 230 kV supply voltage to the station drops below 204 kV when it is activated. Currently the scheme is only armed when the entire Ottawa Area UVLS is armed. It is proposed to modify the scheme so that it can be selectively armed when loading levels are higher than 48MW and under conditions that may result in a circuit M29C line end open at Merivale TS.

Historically the probability of this line end open occurring is low and it would typically occur while terminal maintenance is done at Merivale. By scheduling maintenance during off peak periods, the impact can be significantly reduced. No mitigation measures are therefore recommended at this time. Hydro One and Hydro Ottawa will be monitoring the system performance and the matter will be reconsidered in the next planning cycle based on operating experience.

7.14 Low Power Factor at Almonte TS

7.14.1 Description and Current Status

The IESO's SIA for Almonte T3 replacement noted a low power factor at Almonte TS. This potential issue was also reported in the Outer Ottawa Sub-Region NA report [2].

Hydro One has reviewed the power factor at Almonte TS. The station power factor varies from 0.89 to 0.95 at the LV bus which translates into approximately 0.86 to 0.92 on the HV bus. Part of the reason for the lower power factor is that the station has 29 MW of DG which generally operates at unity power factor. The generation reduces the net power in MW seen at the metering point. This reduction in power results in a lower power factor as seen from the HV bus since the generation does not offset the reactive power demand of the station. No action is required as the load power factor without DG is within the acceptable limits.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER OTTAWA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near term needs are summarized in the Table 8-1 below.

Investments to address the mid-term needs, for cases where there is time to make a decision, will be reviewed and finalized in the next regional planning cycle. These needs are summarized in Table 8-2.

No long term needs were identified at this time. As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years.. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost
1	Almonte TS: addition of breaker to sectionalize line M29C	Construction in the final stages	Hydro One	Dec. 2015	$4.7M
2	Russell TS and Riverdale TS: construction of feeder ties to allow extra load transfers	LDC will lead this work	Hydro Ottawa	2017-2020	$2.0M
3	Lisgar TS: replacement of transformers T1 and T2	Transmitter to carry out this work	Hydro One	Dec. 2017	$13.9M
4	Hawthorne TS: replacement of autotransformers T5 and T6	Transmitter to carry out this work	Hydro One	May 2018	$15.7M
5	Overbrook TS: replacement of transformers T3 and T4	Transmitter to carry out this work	Hydro One	June 2018	$1.1M(1)
6	A6R: additional tap to offload A4K	Transmitter to carry out this work	Hydro One	June 2019	$9-11M
7	Hawthorne TS: replacement of transformers T7 and T8 and add one 44kV feeder position	Transmitter to carry out this work	Hydro One	Oct. 2019	$1.1M(2)
8	New South West Station And Merivale 230/115kV Transformation Capacity	IESO and Hydro Ottawa leading consultation	IESO/Hydro Ottawa	2020	--- (3)
9	King Edward TS: Replace Transformer T4	Transmitter to carry out this work	Hydro One	June 2021	$12M

(1) Incremental cost for larger transformer only.
(2) Incremental cost for larger transformer only. Feeder costs have not been estimated at this time.
(3) The Working Group expects to make a final recommendation on this plan by early 2016.

Table 8-2 List of Mid-Term Needs to be Reviewed in Next Regional Planning Cycle

No.	Need	Timing
1	Bilberry Creek TS - Refurbishment	2023
2	Orleans TS - Reliability	2023(1)
3	79M1 Circuit – Voltage regulation	2023

(1) Performance will be monitored to see if mitigation measures are warranted. Need will be reviewed along with Bilberry Creek TS refurbishment.

9. REFERENCES

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[3]. Hydro One, "Local Planning Report – Supply to East Ottawa Area", 26 November 2015.
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[5]. Hydro One, "OPA Letter – Ottawa Area Regional Planning", 27 June 2014.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Letter%20to%20H1%20RE%20Ottawa.pdf

[6]. Independent Electricity System Operator, "Review of Ontario Interties", 14 October 2014.
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APPENDIX A: STATIONS IN THE GREATER OTTAWA REGION

No.	Station	Voltage (kV)	Supply Circuits
1	Albion TS	230	M30A, M31A
2	Almonte TS	230	M29C (E34M, E29C)
3	Arnprior TS	115	W6CS, C7BM
4	Bilberry Creek TS	115	A2, H9A
5	Bridlewood MTS	115	S7M
6	Carling TS	115	M4G, M5G
7	Centrepoint MTS	115	C7BM
8	Clarence DS	115	79M1
9	Cumberland DS	115	H9A
10	Cyrville MTS	115	A2, A4K
11	Ellwood TS	230	M30A, M31A
12	Epworth MTS	115	M4G, M5G
13	Fallowfield DS	115	S7M
14	Greely DS	115	M1R
15	Hawkesbury MTS	115	79M1
16	Hawthorne	230	-
18	Ivaco	230	D5A
19	Kanata MTS	230	C3S, M32S
20	King Edward TS	115	A4K, A5RK
21	Limebank MTS	115	L2M
22	Lincoln Heights TS	115	C7BM, F10MV
23	Lisgar TS	115	M4G, M5G
24	Longueuil TS	115	B5D, D5A
25	Manordale MTS	115	C7BM
26	Manotick DS	115	S7M
27	Marchwood MTS	115	S7M, W6CS
28	Marionville DS	115	L2M
29	Merivale TS	115	-
30	Moulton MTS	115	A4RK
31	Nation Research TS	115	A2
32	National Aeronautical CTS	115	A8M
33	Navan DS	115	H9A
34	Nepean TS	115	M32S
35	Orleans TS	230 & 115	D5A, H9A
36	Overbrook TS	115	A4K, A5RK
38	Riverdale TS	115	A3RM, A5RK
39	Rockland DS	115	79M1
40	Rockland East DS	115	79M1

41	Russell DS	115	M1R
42	Russell TS	115	A5RK, A6R
43	Slater TS	115	A3RM, A5RK, M4G
44	South Gloucester DS	115	M1R
45	South March	230	C3S, M32S
46	St. Isidore TS	230	B5D, D5A
47	Stewartville TS	115	W3B, W6CS
48	Terry Fox MTS	230	M29C (E34M)
49	Uplands MTS	115	A8M
50	Wendover DS	115	79M1
51	Wilhaven DS	115	H9A
52	Woodroffe TS	115	C7BM, F10MV

APPENDIX B: TRANSMISSION LINES IN THE GREATER OTTAWA REGION

Location	**Circuit Designations**	**Voltage (kV)**
Hawthorne TS – Merivale TS	M30A, M31A	230
Hawthorne TS – St Isidore TS	D5A	230
Merivale TS – Almonte TS	E34C (formally M29C)	230
Merivale TS – South March TS	M32S	230
South March SS – Chats Falls SS	C3S	230
Hawthorne TS – Bilberry Creek TS	A2	115
Hawthorne TS - Merivale TS	A3RM, A8M	115
Hawthorne TS – Overbrook TS	A4K, A5RK	115
Hawthorne TS – Riverdale TS	A6R	115
Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
Merivale TS – Chats Falls TS	C7BM	115
Merivale TS – Hinchey TS	F10MV, V12M	115
Merivale TS – Lisgar TS	M4G, M5G	115
Merivale TS – South March SS	S7M	115
Stewartville TS – South March SS	W6CS	115
Stewartville TS – Barrett Chute TS	W3B	115

APPENDIX C: DISTRIBUTORS IN THE GREATER OTTAWA REGION

Distributor Name	Station Name	Connection Type
Hydro 2000	Longueuil TS	Dx
Hydro Hawkesbury	Hawkesbury MTS	Tx
	Longueil TS	Dx
Hydro One	Almonte TS	Tx
	Arnprior TS	Tx
	Bilberry Creek TS	Tx
	Clarence DS	Tx
	Cumberland DS	Tx
	Greely DS	Tx
	Hawthorne TS	Tx
	Longueil TS	Tx
	Manotick DS	Tx
	Marionville DS	Tx
	Navan DS	Tx
	Orleans TS	Tx
	Rockland DS	Tx
	Rockland East DS	Tx
	Russell DS	Tx
	South Gloucester DS	Tx
	St Isidore TS	Tx
	Stewartville TS	Tx
	Wilhaven DS	Tx
Hydro Ottawa	Albion TS	Tx
	Almonte TS	Dx
	Bilberry Creek TS	Tx
	Bridlewood MTS	Tx
	Carling TS	Tx
	Centrepoint MTS	Tx
	Cyrville MTS	Tx
	Ellwood MTS	Tx
	Nepean Epworth MTS	Tx
	Fallowfield DS	Tx
	Hawthorne TS	Dx, Tx
	Hinchey TS	Tx
	Kanata MTS	Tx
	King Edward TS	Tx

Hydro Ottawa	Limebank MTS	Tx
	Lincoln Heights TS	Tx
	Lisgar TS	Tx
	Manordale MTS	Tx
	Marchwood MTS	Tx
	Moulton MTS	Tx
	Merivale MTS	Tx
	Nepean TS	Tx
	Orleans TS	Tx
	Overbrook TS	Tx
	Richmond MTS	Tx
	Riverdale TS	Tx
	Russell TS	Tx
	Slater TS	Tx
	South Gloucester DS	Dx
	South March TS	Dx, Tx
	St Isidore TS	Dx
	Terry Fox MTS	Tx
	Upland MTS	Tx
	Woodroffe TS	Tx
Ottawa River Power Corporation	Almonte TS	Dx
Renfrew Hydro	Stewartville TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1 Stations Coincident Load Forecast (MW)

Area	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Center 115	King Edward TS	71	70	67	69	75	75	75	76	77	78	77	77	78	77	77
	Lisgar TS	75	64	67	71	74	74	75	75	87	88	90	90	90	89	89
	Overbrook TS	130	85	91	94	100	101	102	108	110	111	112	113	114	115	116
	Riverdale TS	105	102	99	102	111	112	112	114	118	119	120	121	123	123	124
	Russell TS	69	61	63	65	73	73	73	73	73	73	73	73	73	73	73
	Slater TS	118	106	113	114	116	115	114	114	113	112	112	111	110	110	110
	Total	**569**	**488**	**501**	**515**	**549**	**549**	**550**	**559**	**578**	**581**	**584**	**586**	**588**	**589**	**590**
Center 230	Albion	88	71	72	73	73	73	73	74	74	75	75	76	77	77	77
	Ellwood TS	59	27	28	28	28	28	28	28	28	28	28	28	28	29	29
	Hawthorne	153	107	117	120	124	126	128	132	137	136	140	138	139	138	138
	Total	**300**	**206**	**217**	**221**	**225**	**227**	**229**	**234**	**239**	**239**	**243**	**243**	**244**	**243**	**243**
East 115	Bilberry Creek TS	85	87	54	54	54	54	54	54	54	55	55	55	55	55	56
	Cumberland DS	15	5	6	6	6	6	6	6	6	6	6	6	6	7	7
	Cyrville MTS	59	24	30	35	35	37	38	40	42	44	44	44	44	44	44
	Moulton MTS	34	31	32	32	32	32	32	32	33	33	33	33	34	34	34
	Nation Research TS	25	18	18	18	18	18	18	18	18	18	18	18	18	18	18
	Navan DS	15	6	6	6	6	6	6	6	6	6	6	6	5	5	5
	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Wilhaven DS	58	49	4	5	5	6	6	6	7	10	11	12	12	14	16
	Total	**340**	**221**	**193**	**201**	**202**	**205**	**208**	**210**	**215**	**221**	**224**	**226**	**228**	**232**	**237**
East 230	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Total	51	**0**	**45**	**46**	**46**	**47**	**48**	**48**	**50**	**50**	**51**	**52**	**54**	**55**	**57**
South 115	Greely DS	40	17	18	18	18	18	18	18	18	18	18	19	19	19	19
	Limebank MTS	68	44	47	49	52	54	56	59	64	70	76	82	89	88	88
	Marionville DS	28	13	14	14	14	14	14	14	14	14	14	14	15	15	15
	National Aeronautical CTS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Russell DS	8	3	3	3	3	3	3	3	3	3	3	3	3	3	4
	South Gloucester DS	8	4	4	4	4	4	4	4	4	4	5	5	5	5	5
	Uplands MTS	30	25	26	26	27	27	27	27	28	29	29	30	30	30	30
	Total	**182**	**109**	**112**	**115**	**118**	**121**	**123**	**126**	**133**	**140**	**147**	**154**	**161**	**161**	**161**
South West 115	Fallowfield DS	48	36	39	38	41	49	51	54	58	61	67	71	76	82	89
	Manotick DS	17	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Richmond DS	5	9	10	11	13	31	34	36	36	37	38	39	38	38	38
	Total	**70**	**52**	**56**	**56**	**61**	**87**	**92**	**97**	**101**	**106**	**112**	**118**	**122**	**127**	**134**

West 115	Bridlewood MTS	37	22	22	23	22	22	22	23	39	39	39	39	39	39	39
	Carling TS	93	82	83	84	85	86	86	87	93	95	96	98	99	100	102
	Centrepoint MTS	35	17	17	17	17	17	16	16	16	16	16	16	16	16	16
	Epworth	25	15	15	16	16	16	16	15	15	15	15	15	15	15	15
	Hinchey TS	77	58	60	62	66	68	70	72	67	71	75	79	83	87	90
	Lincoln Heights TS	71	45	45	45	45	44	44	44	49	49	49	48	48	48	48
	Manordale MTS	22	11	11	11	11	11	11	11	11	11	11	11	10	10	10
	Marchwood MTS	34	34	34	34	35	34	34	34	35	34	35	35	35	36	37
	Merivale TS	18	14	14	13	15	15	15	15	16	17	19	20	20	19	19
	Woodroffe TS	92	39	40	41	42	42	43	43	53	54	55	56	56	57	58
	Total	**504**	**336**	**340**	**346**	**353**	**355**	**356**	**362**	**395**	**402**	**410**	**417**	**421**	**427**	**434**
West 230	Kanata MTS	55	46	47	47	47	47	46	47	47	48	48	48	48	48	48
	Nepean TS	144	145	144	143	143	141	139	138	136	134	132	130	128	127	127
	South March	109	116	110	115	119	123	126	131	123	104	104	104	104	103	104
	Terry Fox MTS	90	39	50	78	83	65	65	64	63	63	62	61	60	60	60
	Total	**397**	**346**	**351**	**383**	**391**	**376**	**376**	**380**	**370**	**349**	**345**	**343**	**340**	**337**	**338**
Outer East 115	Clarence DS	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Hawkesbury MTS	18	15	15	15	15	15	15	15	15	16	16	16	16	16	16
	Rockland DS	9	8	8	8	8	8	8	9	9	9	9	9	9	9	9
	Rockland East DS	15	12	12	12	12	12	12	12	13	13	13	13	13	13	13
	Wendover TS	34	12	12	12	12	12	12	12	14	14	14	14	13	13	13
	Total	**80**	**49**	**49**	**50**	**50**	**50**	**50**	**51**	**55**	**55**	**55**	**55**	**55**	**55**	**56**
Outer East 230	Ivaco	100	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	Longueuil TS	98	31	31	31	31	30	30	30	30	30	30	30	30	30	30
	St. Isidore TS	52	35	35	36	35	35	35	35	35	35	35	35	35	35	35
	Total	**249**	**106**	**106**	**106**	**106**	**106**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**
Outer West 115	Arnprior TS	51	36	36	36	36	35	35	35	34	34	34	34	34	34	34
	Stewartville TS	55	30	30	30	46	46	45	45	45	45	45	45	45	45	45
	Total	**106**	**66**	**66**	**66**	**82**	**81**	**80**	**80**	**79**	**79**	**79**	**79**	**79**	**79**	**79**
Outer West 230	Almonte TS	100	35	34	34	34	34	33	33	33	33	33	33	33	33	33
	Total	**100**	**35**	**34**	**34**	**34**	**34**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**
Regional Total		**2948**	**2013**	**2069**	**2140**	**2219**	**2238**	**2249**	**2285**	**2352**	**2360**	**2388**	**2411**	**2430**	**2445**	**2468**

Table D-2 Stations Non Coincident Forecast (MW)

Area	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Center 115	King Edward TS	71	88	84	87	93	93	93	94	96	97	97	96	97	96	96
	Lisgar TS	75	67	70	74	78	78	78	79	91	92	94	94	94	93	93
	Overbrook TS	130	84	91	93	99	100	102	107	109	110	111	112	113	114	115
	Riverdale TS	105	78	76	78	84	85	86	87	90	91	92	93	93	94	95
	Russell TS	69	74	77	80	90	89	89	89	89	89	89	90	90	90	90
	Slater TS	118	125	133	134	136	135	134	134	133	132	131	131	130	129	129
	Total	**569**	**516**	**530**	**546**	**580**	**581**	**581**	**590**	**608**	**612**	**614**	**615**	**617**	**617**	**619**
Center 230	Albion	88	77	79	80	80	80	80	80	81	82	82	83	84	84	84
	Ellwood TS	59	43	43	44	44	44	43	44	44	44	44	44	45	45	45
	Hawthorne	153	103	115	120	124	126	128	132	137	136	140	138	139	138	138
	Total	**300**	**223**	**238**	**243**	**248**	**250**	**251**	**256**	**262**	**262**	**266**	**266**	**267**	**266**	**267**
East 115	Bilberry Creek TS	85	87	54	54	54	54	54	54	54	55	55	55	55	55	56
	Cumberland DS	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Cyrville MTS	59	25	31	37	37	39	40	42	44	47	47	47	47	47	47
	Moulton MTS	34	40	40	40	41	40	40	41	41	41	42	42	42	43	43
	Nation Research TS	25	18	19	19	19	19	18	19	19	19	18	18	18	18	18
	Navan DS	15	6	6	6	6	6	5	5	5	5	5	5	5	5	5
	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Wilhaven DS	58	53	4	5	5	6	6	6	7	10	11	12	12	14	16
	Total	**340**	**231**	**200**	**208**	**209**	**212**	**215**	**217**	**223**	**229**	**231**	**234**	**236**	**240**	**244**
East 230	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Total	**51**	**0**	**45**	**46**	**46**	**47**	**48**	**48**	**50**	**50**	**51**	**52**	**54**	**55**	**57**
South 115	Greely DS	40	35	35	36	36	36	36	36	36	37	37	37	38	38	38
	Limebank MTS	68	47	49	52	54	56	59	61	67	73	79	86	93	92	92
	Marionville DS	28	31	31	31	32	32	31	32	32	32	33	33	33	34	34
	National Aeronautical CTS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Russell DS	8	12	13	13	13	13	13	13	13	13	13	13	13	13	13
	South Gloucester DS	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Uplands MTS	30	20	20	20	21	21	21	21	22	22	23	23	24	23	23
	Total	**182**	**151**	**155**	**159**	**162**	**165**	**167**	**171**	**178**	**185**	**193**	**201**	**209**	**209**	**209**
South West 115	Fallowfield DS	48	45	49	48	51	61	64	68	72	76	84	89	95	102	111
	Manotick DS	17	8	8	9	9	9	9	9	9	9	9	9	9	9	9
	Richmond DS	5	7	7	8	10	22	24	25	26	27	27	28	28	27	27
	Total	**70**	**60**	**64**	**65**	**69**	**92**	**97**	**102**	**107**	**112**	**120**	**126**	**131**	**139**	**147**

West 115	Bridlewood MTS	37	34	34	35	35	34	34	35	61	61	60	61	61	60	60
	Carling TS	93	88	89	90	91	92	92	93	100	102	103	105	106	107	109
	Centrepoint MTS	35	21	21	21	21	21	21	21	21	21	20	20	20	20	20
	Epworth	25	15	15	16	16	16	16	16	16	15	15	15	15	15	15
	Hinchey TS	77	47	49	51	54	55	57	59	54	57	61	64	67	70	73
	Lincoln Heights TS	71	48	48	48	48	47	47	47	53	52	52	52	51	51	51
	Manordale MTS	22	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	Marchwood MTS	34	35	35	35	36	35	35	36	36	36	36	36	36	37	38
	Merivale TS	18	18	19	18	20	20	20	20	22	23	26	27	26	26	26
	Woodroffe TS	92	35	36	36	37	38	38	39	47	48	49	49	50	51	51
	Total	**504**	**351**	**355**	**361**	**368**	**369**	**369**	**375**	**419**	**425**	**432**	**439**	**443**	**448**	**454**
West 230	Kanata MTS	55	87	88	88	88	88	87	88	89	89	90	90	90	90	90
	Nepean TS	144	153	152	151	150	148	146	145	144	141	139	137	135	133	133
	South March	109	98	93	97	101	104	107	110	102	87	87	87	87	86	87
	Terry Fox MTS	90	44	57	88	93	74	73	72	71	71	70	69	68	67	67
	Total	**397**	**382**	**390**	**424**	**432**	**414**	**412**	**416**	**406**	**389**	**385**	**383**	**379**	**377**	**377**
Outer East 115	Clarence DS	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Hawkesbury MTS	18	17	17	17	17	17	17	17	18	18	18	18	18	19	19
	Rockland DS	9	17	17	17	18	18	18	18	19	19	19	19	19	19	19
	Rockland East DS	15	11	11	11	12	12	12	12	13	13	13	13	13	13	13
	Wendover TS	34	9	9	9	9	9	9	10	11	11	11	10	10	10	10
	Total	**80**	**56**	**56**	**56**	**57**	**57**	**57**	**57**	**62**	**62**	**63**	**63**	**63**	**63**	**63**
Outer East 230	Ivaco	100	92	92	92	92	92	92	92	92	92	92	92	92	92	92
	Longueuil TS	98	44	44	44	44	43	43	43	43	43	43	43	43	43	43
	St. Isidore TS	52	48	48	48	48	47	47	47	47	47	47	47	47	47	47
	Total	**249**	**184**	**184**	**184**	**184**	**183**	**182**	**182**	**182**	**182**	**182**	**182**	**182**	**182**	**182**
Outer West 115	Arnprior TS	51	51	51	51	51	50	49	49	49	49	49	49	49	49	49
	Stewartville TS	55	32	32	32	49	49	48	48	48	48	48	48	48	48	48
	Total	**106**	**83**	**82**	**82**	**100**	**99**	**97**	**97**	**96**	**96**	**96**	**96**	**96**	**96**	**96**
Outer West 230	Almonte TS	100	48	48	47	47	47	46	46	45	45	45	45	45	45	45
	Total	**100**	**48**	**48**	**47**	**47**	**47**	**46**	**46**	**45**	**45**	**45**	**45**	**45**	**45**	**45**
Region Total		**2948**	**2284**	**2346**	**2421**	**2503**	**2514**	**2522**	**2558**	**2637**	**2650**	**2680**	**2702**	**2722**	**2738**	**2762**

APPENDIX E: LIST OF ACRONYMS

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

GTA North

Regional Infrastructure Plan

February 5, 2016

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

With support from:

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Independent Electricity System Operator
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PowerStream Inc.
Toronto Hydro Electric System Ltd.

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DISCLAIMER

This Regional Infrastructure Plan (“RIP”) report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE ("TSC") REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN FACILITIES THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA NORTH REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- PowerStream Inc.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It follows the completion of the York Sub-Region's Integrated Regional Resource Planning ("IRRP") by the IESO in April 2015 and the Western Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for the York Sub-Region over the near-term (up to 5 years) and the mid-term (5 to 10 years). The York Region IRRP has identified the need for additional transformation capacity in Markham, Northern York Region and Vaughan in the mid-term. These mid-term needs are linked to long-term (beyond 10 years) transmission capacity needs.

No needs have been identified over the near-term and mid-term for the Western Sub-Region except for load restoration for the loss of double circuit 230 kV line V43/V44. It is recommended that this need be assessed as part of the IESO led GTA West bulk system planning initiative and as a result is not addressed in this RIP.

The major infrastructure investments planned for the GTA North Region over the near-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Vaughan #4 MTS	Q1 2017	$25M*
2	Holland breakers, disconnect switches and special protection scheme	Q4 2017	$32M
3	Parkway belt switches	Q4 2018	$4-6M

* PowerStream's station cost. Hydro One line connection cost is currently being estimated

The planning is continuing for the mid-term and long-term needs. These needs, and the options to address these them, are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through the Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

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1 INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Enersource Hydro Mississauga Inc. ("Enersource"), Hydro One Brampton Networks Inc. ("Hydro One Brampton"), Hydro One Distribution, Newmarket-Tay Power Distribution Ltd. ("NTPDL"), PowerStream Inc. ("PowerStream"), Toronto Hydro-Electric System Limited ("THESL"), and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA North Region includes most of the Regional Municipality of York and parts of the City of Toronto, Brampton, and Mississauga (see Figure 1-1). Electrical supply to the Region is provided through 230 kV transmission circuits, fifteen step-down transformer stations ("TS"), and the York Energy Centre ("YEC") generating station ("GS").

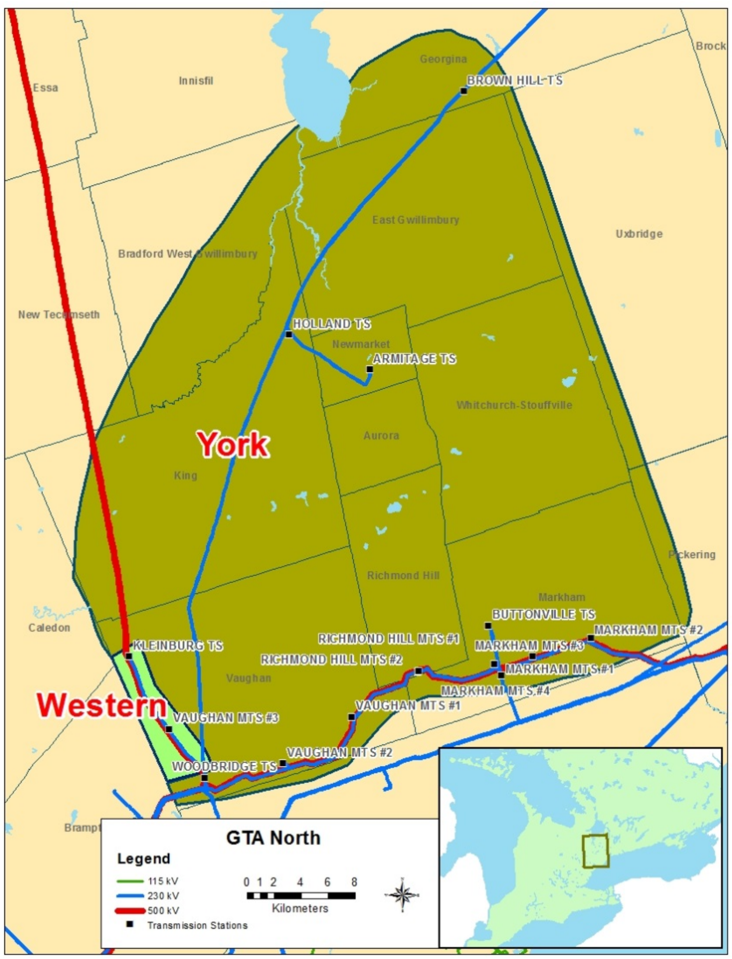

Figure 1-1 GTA North Region

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015 to 2025) identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address them.
- Consideration of long-term needs identified in the York Region IRRP

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led

[1] Also referred to as Needs Screening.

stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

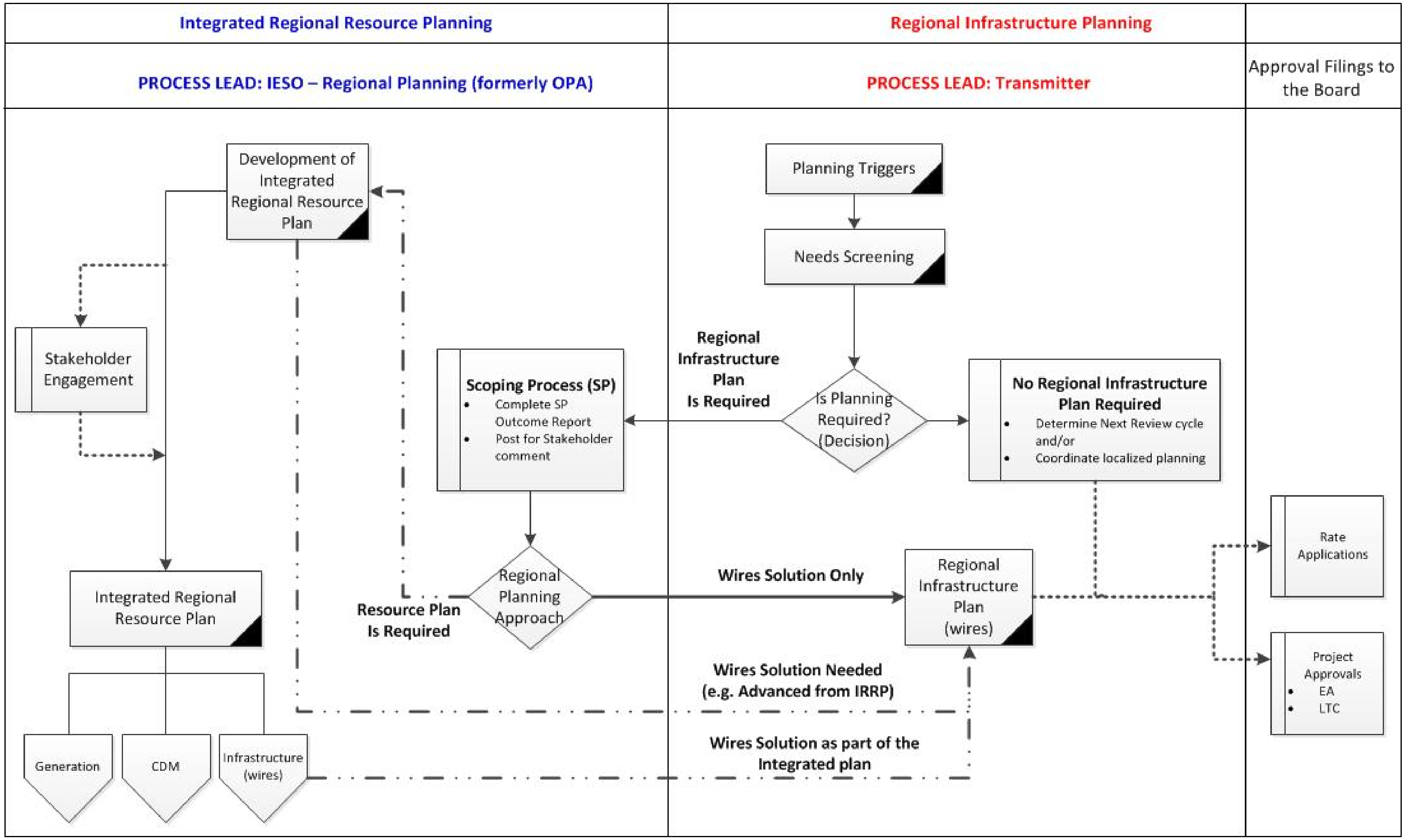

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
    - Net peak demand forecast at the transformer station level. This includes the effect of any DG or CDM programs.
    - Existing area network and capabilities including any bulk system power flow assumptions; and,
    - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

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

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

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

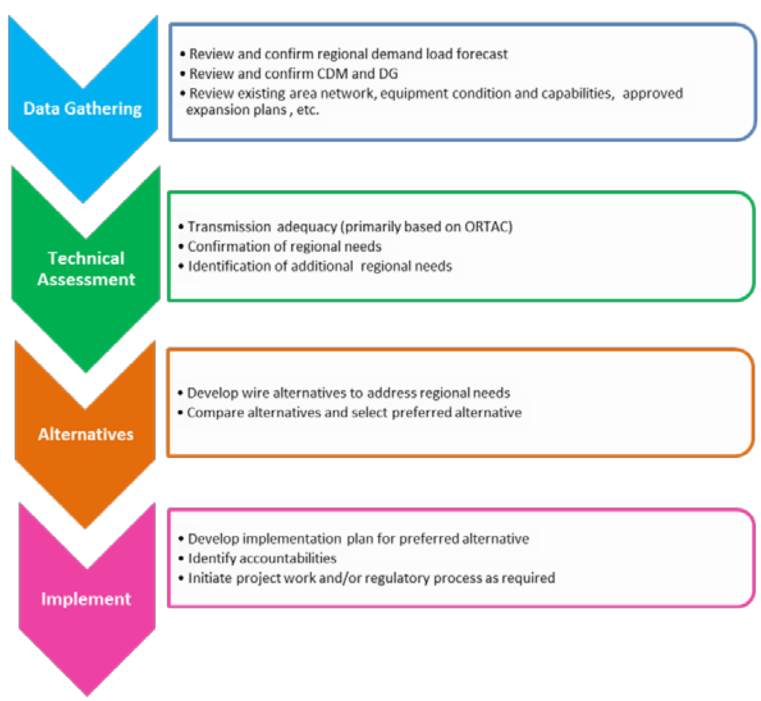

Figure 2-2 RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE YORK SUB-REGION AND THE WESTERN SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1900MW.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

The April 2015 York Region Integrated Regional Resource Plan ("IRRP"), prepared by the IESO in conjunction with Hydro One, PowerStream and Newmarket-Tay Power, focused solely on the York Sub-Region. The June 2014 GTA North Western Sub-Region Needs Assessment report, prepared by Hydro One, considered the Western Sub-Region. A map of the GTA North Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 York Sub-Region

The York Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

For regional planning purposes, the York Sub-Region is further classified into Northern York Area and Southern York Area to reflect the layout of the region's electricity infrastructure. The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and PowerStream.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes eight municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is PowerStream.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Western Sub-Region

The Western Sub-Region comprises the Western portion of the municipality of Vaughan. Electrical supply to the sub-region is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the "Kleinburg tap") that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied in the sub-region are PowerStream and Hydro One Distribution. Embedded LDCs supplied in the sub-region include Enersource, Hydro One Brampton and Toronto Hydro.
During the Needs Assessment phase for the Western Sub-Region, a load restoration need for the loss of V43/V44 was identified. It was recommended that a plan to address this need be included in the IESO led GTA West bulk system planning initiative and therefore this need is not addressed in this RIP.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

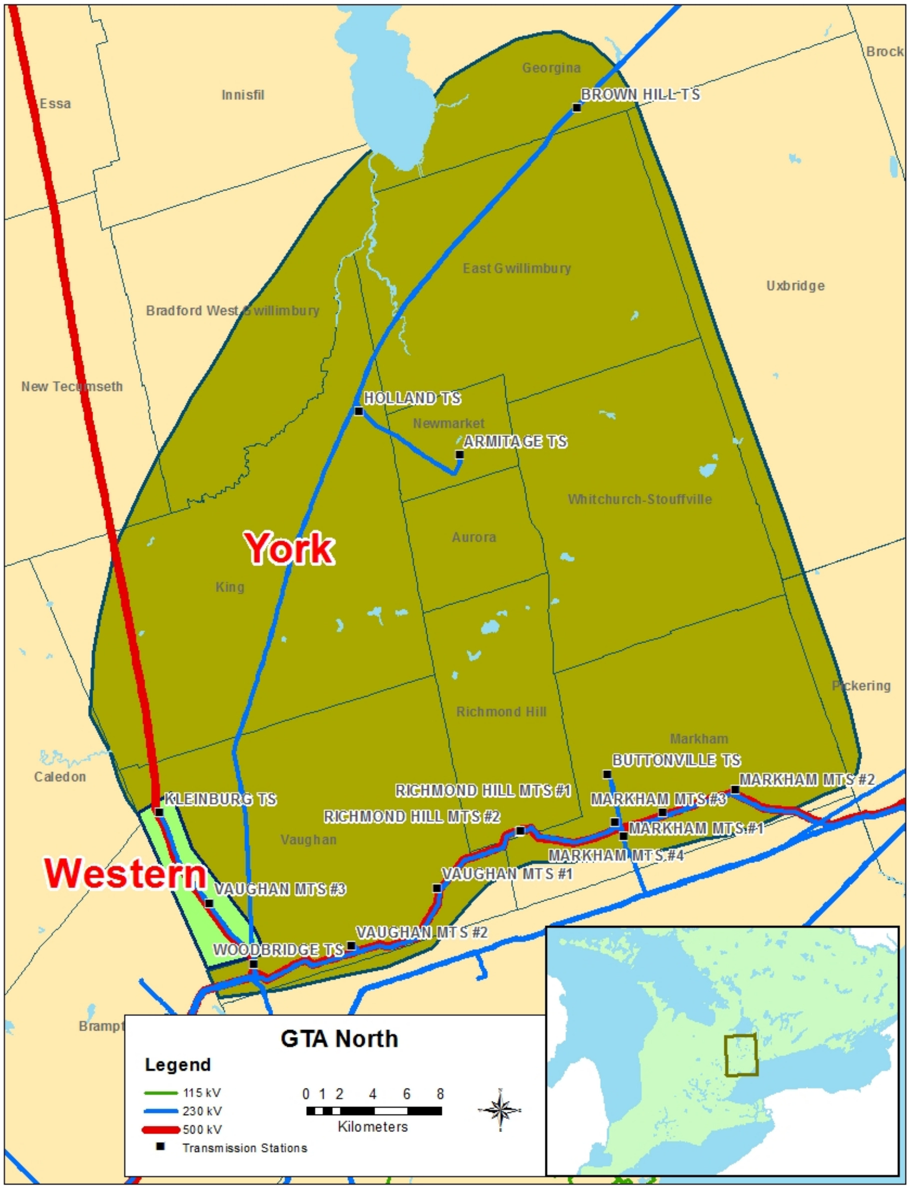

Figure 3-1 GTA North Region – Supply Areas

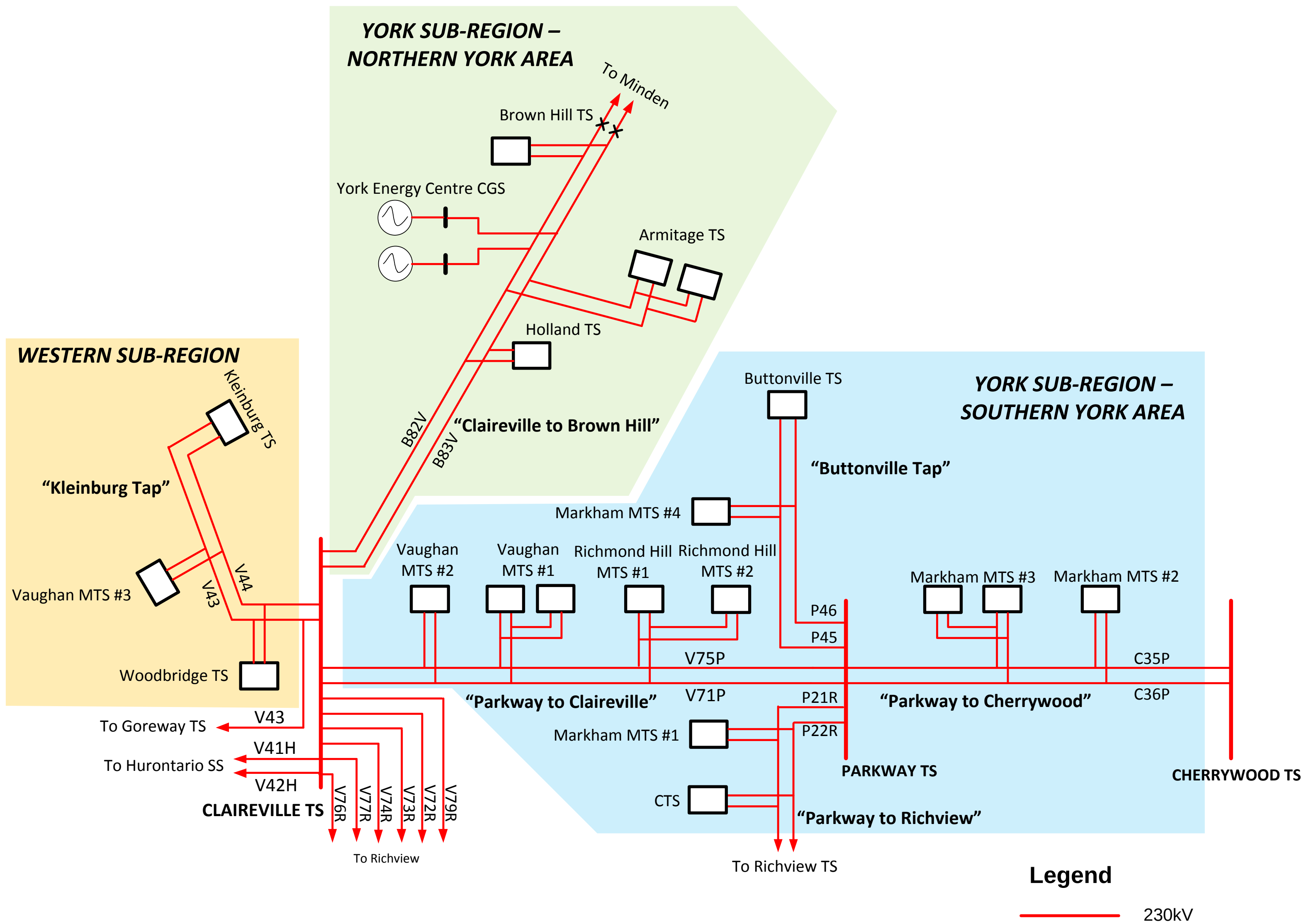

Figure 3-2 GTA North Transmission Single Line Diagram

4 TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA NORTH REGION.

A brief listing of the completed development projects along with their in-service dates over the last 10 years is given below:

- Holland TS and low voltage capacitor banks (2009) – to increase transformation capacity for the Northern York Area.
- Parkway 500-230kV autotransformer station (2006) – to increase transmission supply capacity to GTA North
- Parkway x Richmond Hill 230kV double circuit line (2006) – to improve reliability of supply to Southern York Area
- Connect Markham #4 MTS (2009) – to increase transformation capacity for the Southern York Area.
- Increased the size of the capacitor banks at Armitage TS (2006) – to improve reliability of supply to the Northern York Area.
- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.

The following development projects are currently underway:

- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.
- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the York Sub-Region.

5 FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of approximately 2.1% annually up 2020, and 1.8% between 2020 and 2025. The growth rate varies across the Region.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast. The coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix D. The net load forecast takes into account the expected impacts of conservation programs and distributed generation resources.

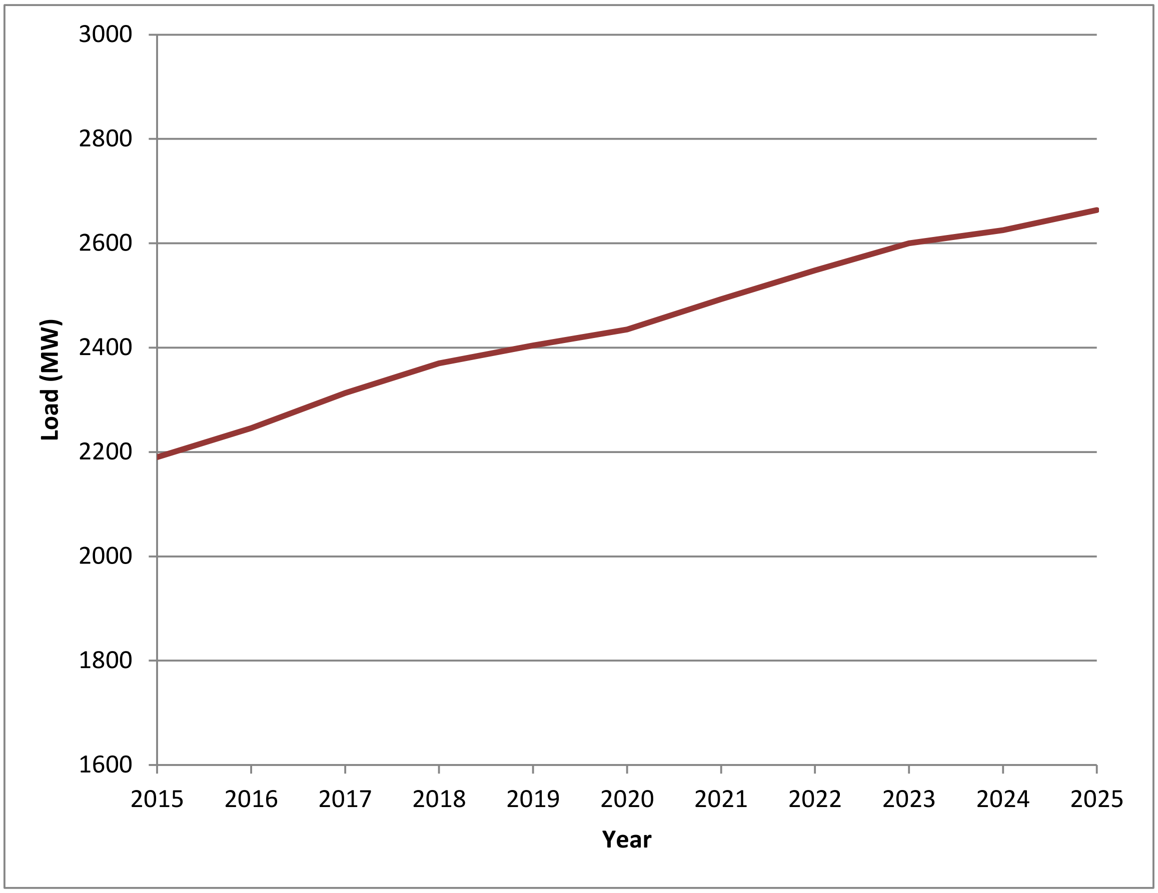

Figure 5-1 GTA North Region Extreme Summer Weather Coincident Peak Net Load Forecast

The station coincident peak net loads used in the RIP are as given in the York Region IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region[2]. RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IRRP and NA for the Western Sub-Region was still valid.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor which is consistent with ORTAC[4]. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6 ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA NORTH REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region; the findings of these studies are input to the RIP:

1) IESO's York Region Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – GTA North – Western Sub-Region – June 27, 2014[2]

The York region IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Holland TS Breakers project and the Vaughan #4 MTS project were initiated to provide adequate load supply capability for the York Sub-Region while the York Region IRRP study was still underway. A detailed description and status of the Holland TS Breakers project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region assuming the Holland TS Breakers project is in-service using the latest Regional Forecast based on the IRRP load growth scenario as given in Section 5. Sections 6.1- 6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA North Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1.1	Additional transformation capacity in Vaughan (new Vaughan MTS #4 on circuits B82V/B83V)	2017
	7.1.4	Additional transformation capacity in Markham	2022(3)
	7.1.3	Additional transformation capacity in Vaughan(1)	2023(3)
	7.2.2	Additional transformation capacity in Northern York Area(1)	2023
Transmission Capacity	7.2.1	Capacity of the Claireville to Brown Hill (B82V/B83V) transmission line exceeded	2021
Load Security	7.2.1	Claireville to Brown Hill line (B82V/B83V)	2018
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
Load Restoration	7.2.1	Claireville to Brown Hill line (B82V/B83V)	Today
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
	7.3.1	Claireville to Kleinburg line (V43/V44) – restoration need only(2)	Today

(1) There are long-term transmission supply needs associated with new transformation capacity
(2) Restoration need to be assessed as part of the IESO led GTA West bulk system planning initiative
(3) PowerStream is currently reviewing their forecast and has advised that the need date for Markham may change to 2023 and the need date for Vaughan may change to 2026.

6.1 Adequacy of York Sub-Region Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The York Sub-Region is comprised of the following 230 kV circuits. Refer to Figure 3-2.

Southern York Area:

a) Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
b) Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
c) Parkway TS to Buttonville TS **(**"Buttonville Tap") 230 kV circuits: P45 and P46.
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Northern York Area:

- Claireville TS to Brown Hill TS 230 kV circuits: B82V and B83V.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of twelve step-down transformers stations in the York Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in the York Sub-Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS#1*	Markham MTS#2*
Markham MTS#3*	Markham MTS#4*	Richmond Hill MTS*
Vaughan MTS#1*	Vaughan MTS#2*	Industrial Customer

*Stations owned by PowerStream

Based on the LTR of these load stations, additional capacity is required in Vaughan in 2017 which will be addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2022, and additional capacity will be needed in both Vaughan and Northern York Area as early as 2023. However, PowerStream has advised that their forecast for Markham and Vaughan is currently under review, and that these need dates may change to 2023 and 2026 respectively.

The station loading in each area and the associated station capacity and need dates are summarized in Table 6-3.

Table 6-3 Adequacy of the Step-Down Transformation Facilities in the York Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)*	Need Date
Northern York Area (Armitage, Holland)	485	430	2023
Northern York Area (Brown Hill)	184	74	-
Southern York Area (Markham/Richmond Hill)	956	833	2022
Southern York Area (Vaughan)	612**	459	2023

* Weather adjusted summer peak as per York Region IRRP
** Includes future capacity provided by Vaughan #4 MTS. It does not include Vaughan MTS #3 which is in the Western Sub-Region

6.2 Adequacy of Western Sub-Region Facilities

The Western Sub-Region is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-2. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.1 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the York Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in the Western Sub-Region

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by PowerStream

The forecast individual station forecast loads are given in Appendix D. Based on the forecast loads these transformer stations are adequate over the study period. The total station capacity and 2015 loads in Western Sub-Region are given in Table 6-5.

Table 6-5 Adequacy of Step-Down Transformation Facilities – Western Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)	2025 Summer Loading (MW)
Western Sub-Region (Vaughan/Kleinburg)	509	394	409

6.3 Other Items Identified During Regional Planning

6.3.1 Load Security and Restoration in the Southern York Area

The York Region IRRP report had identified load security and restoration needs for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P exceeds the 600 MW limit as per ORTAC security criteria. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Working Group recommendations to address the needs are discussed in more detail in Section 7.1.2.

6.3.2 Load Restoration in Western Sub-Region

The Needs Assessment report for the Western Sub-Region had identified a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The Working Group has reviewed the need and reaffirmed the NA recommendation that this need be considered as part of the IESO led GTA West bulk system planning initiative.

6.4 Long-Term Regional Needs

As shown in Section 6.1.2 additional transformation capacity is required in the mid-term. With continued demand growth, the transmission system supplying these stations is also expected to reach its limits. The York Region IRRP had identified the need to coordinate the long term transmission needs with plans to address the station capacity needs.

The GO Rail Electrification Project is an initiative by Metrolinx to convert several rail corridors from a diesel to an electric-based system. GO's Barrie and Stouffville corridors are part of this plan and it is expected that parts of these rail corridors will be supplied by transmission infrastructure in the GTA North Region. At the time of this RIP the electrification project is still in the planning phase, but the impact of this project on the electrical infrastructure in the GTA North Region will need to be monitored as the plans are developed.

The options to address the transformation capacity needs are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through a Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

7 REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA North Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region.[2] Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2015 to 2020) and the mid-term needs cover the second half of the study period (2020-2025).

7.1 Southern York Area

7.1.1 Increase Transformation Capacity in Vaughan

7.1.1.1 Description

The load forecast reflects substantial growth around the City of Vaughan, mainly around the northern boundaries, as new developments are being made in the area. As a result, based on the net demand forecast a new transformer station is needed by 2017 to ensure adequate transformation capacity is available. This need was also identified as a near-term need in the 2015 York Region IRRP.

7.1.1.2 Recommended Plan and Current Status

Due to the need to provide transformation capacity by 2017, work on building a new station was initiated by PowerStream while the York Region IRRP was still under way. The IRRP Working Group recommended that the new station connect to the Claireville to Brown Hill lines (230 kV circuits B82V/B83V) approximately 12 km north of Claireville TS.[5] Refer to Figure 7.1.

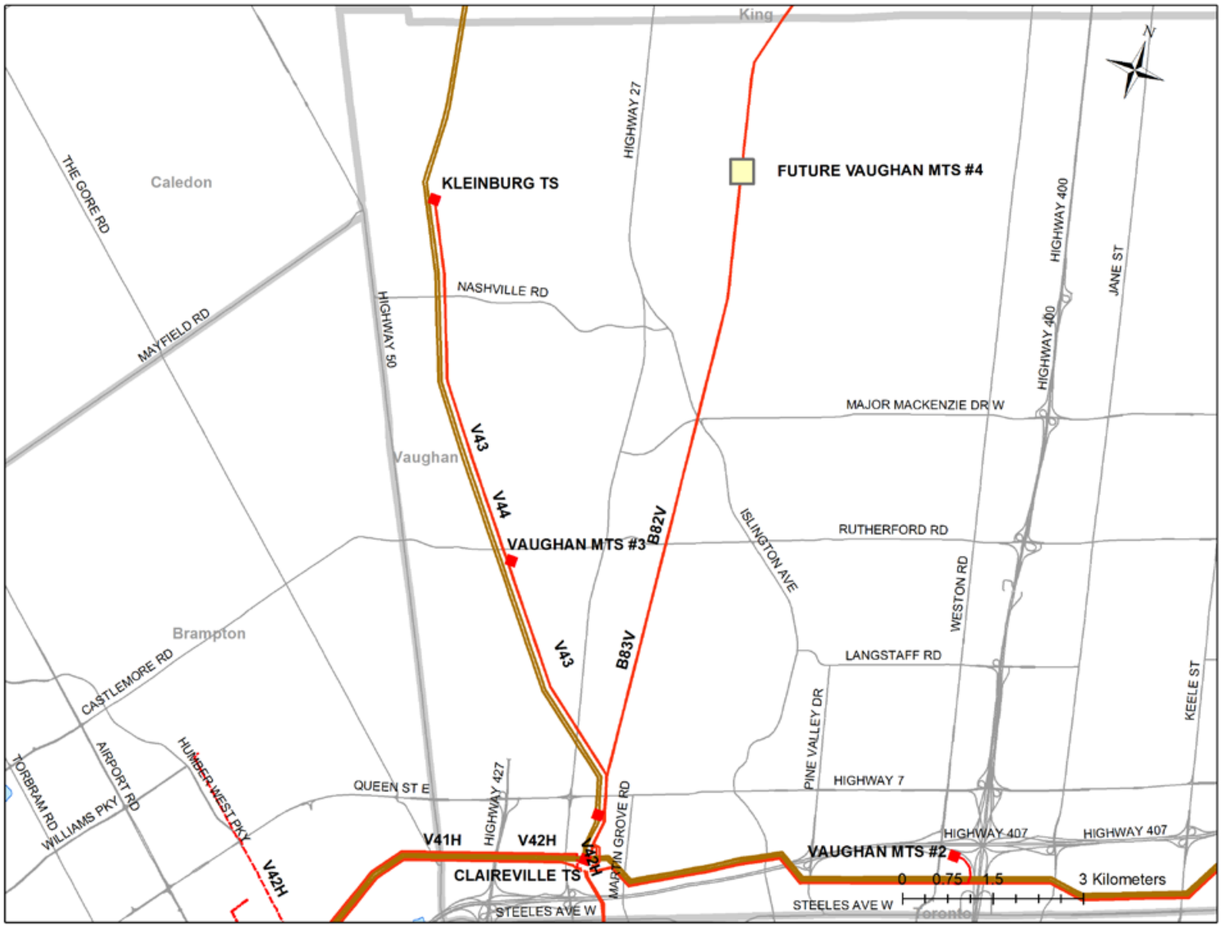

Figure 7-1 Vaughan MTS #4

The new station, Vaughan MTS #4, will provide 153 MW of 27.6 kV transformation capacity and is expected to be in-service by May 2017. Hydro One will construct the line tap to connect the new station to the B82V/B83V circuits.

PowerStream's estimated cost for the station is $25M. The Hydro One line connection cost is currently being estimated. The Hydro One line connection cost will be recovered from rate revenue in accordance with the TSC.

7.1.2 Improve Load Restoration Capability on the Parkway to Claireville Line

7.1.2.1 Description

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. There are two needs identified for this system:

- The load security criteria in ORTAC[4] limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.
- The load restoration criteria requires that any load that is interrupted that exceeds 250 MW must be restorable within 30 minutes. At present, this may not be possible on the Parkway to Claireville line under certain operating conditions.

7.1.2.2 Recommended Plan and Current Status

The York Region IRRP recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. The switches will not reduce the amount of load that is interrupted, however they will enable Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously. This work is covered under the V71P/V75P - Install 230 kV In-line Switches project.

Hydro One has established a project to install the two 230 kV in-line switches onto the V71P/V75P double circuit line with one switch installed on each circuit. The project is currently in the detailed design and estimation phase. The cost of this project is approximately $4-6 million and it is anticipated to be a transmission pool investment. The planned in-service date is May 2018.

7.1.3 Mid-Term Need to Increase Transformation Capacity in Vaughan

7.1.3.1 Description

The planned Vaughan MTS #4 will provide near term transformation capacity for Vaughan beginning in 2017. However, the load forecast shows that additional transformation capacity will be needed in Vaughan as early as 2023. There isn't sufficient transmission capacity available to supply another transformation station on the Claireville to Brown Hill line. Therefore a plan to increase transmission capacity to the area will be required before a plan for a new transformation station can be committed.

7.1.3.2 Recommended Plan and Current Status

Given the time required to build new transmission facilities, the York Region IRRP[1] had advised that it was necessary to identify a preferred alternative no later than 2018 to address both the transformation capacity need as well as the transmission capacity need. However, PowerStream is currently reviewing their load forecast for Vaughan and has advised that the need date for new transformation capacity may change to 2026. An update to the York Region IRRP is currently scheduled for 2017 to review the need date and develop a preferred plan for building and connecting additional transformation capacity in Vaughan.

7.1.4 Mid-Term Need to Increase Step-Down Transformation Capacity in Markham

7.1.4.1 Description

The step-down transformation capacity in Markham will be exceeded as early as 2022. The York Region IRRP has identified that additional transmission facilities will be required to supply the new station. It is expected that the IESO will continue to explore non-wires options, in addition to wires options, through the IRRP process.

New developments attributable to forecasted load growth in the area are generally further north, away from existing transmission facilities. The ORTAC's[4] load restoration criteria will need to be considered in the further development of any detailed wires options. Non-wires options are beyond the scope of this RIP, but there are two main wires options for supplying a new Markham transformer station.

Option 1 - Connect to 230kV circuits C35P/C36P between Parkway TS and Cherrywood TS
The Parkway to Cherrywood line (C35P/C36P) connects two major bulk transmission stations, Parkway TS and Cherrywood TS, and also supplies load stations Markham MTS #3 (2 stations) and Markham MTS #2. There is transmission capacity available on these circuits to connect another transformer station.

Option 2 – Connect to 230kV double circuit line P45/P46 between Parkway TS and Buttonville TS
The Buttonville Tap (P45/P46) currently supplies two stations, Markham MTS #4 and Buttonville TS radially from Parkway TS. The transmission capacity on these circuits is thermally limited by a section less than 1 km long, so it would be necessary to increase the thermal capacity of these circuits in order to fully supply another station.

Extending the transmission circuits discussed would allow the point of supply to be nearer to the area of expected load growth and therefore reduce the amount of distribution facilities that would be needed.

7.1.4.2 Recommended Plan and Current Status

The existing transmission lines are not near the areas of expected load growth so the additional transmission costs to supply a new station nearer to the load need to be considered alongside the distribution costs. PowerStream estimates the incremental distribution costs for a station supplied by existing transmission lines to be on the order of $10-$50M higher than would be required for a station located nearer to the load.

Given that this need is a mid-term need, the York Region IRRP[1] identified a number of non-wires approaches that may address or defer the need for further transformation capacity. Such alternatives include CDM, DG, large generation and other local community initiatives and further monitoring of the load growth was recommended. In order to have facilities in-service to meet a summer 2022 need, it is recommended to continue wires planning, in addition to other non-wires alternatives, to meet this need and to identify a preferred solution by the end of 2017. This timeline allows approximately 4.5 years for detailed estimating, engineering, approvals, construction and commissioning if a wires option is identified as the preferred alternative. However, PowerStream is currently reviewing their load forecast for Markham and has advised that the need date for new transformation capacity may change to 2023. It is expected that the need date will be reviewed and a preferred solution will be identified in the York Region IRRP update process which is currently scheduled for 2017.

7.2 Northern York Area

7.2.1 Increase Capacity and Load Restoration Capability on Claireville to Brown Hill Line

The transmission capacity, load security and load restoration requirements are near-term needs for the Claireville to Brown Hill line (circuits B82V/B83V). These needs were identified in the 2015 York Region IRRP[1]. The Claireville to Brown Hill transmission line and local generation (York Energy Centre) combined are capable of supplying 600 MW of load. This limit is based on the ORTAC[4] load security criteria, which limits the amount of load that can be lost for two elements out of service to 600 MW. This is the most restrictive limit in this system and therefore defines the amount of load that can be supplied. With continued load growth at the stations supplied by this line as well as the future Vaughan #4 MTS (described in section 7.1), it is expected that load security criteria will be exceeded by 2018 based on the net demand forecast.

The load restoration need is based on the ORTAC[4] load restoration criteria that requires any load lost exceeding 250 MW to be restorable within 30 minutes. Based on the current net peak demand forecast, the loss of the Claireville to Brown Hill line will exceed this threshold and there are insufficient transmission and distribution facilities to restore sufficient load within 30 minutes in order to respect the criteria.

7.2.1.1 Recommended Plan and Current Status

Hydro One is expanding the Holland TS station to include two, 230kV inline circuit breakers and six motorized disconnect switches to increase the transmission capacity as well as the load restoration capability of this system. The project includes a load rejection and generation rejection special protection scheme (“SPS”). The purpose of the SPS is to ensure that the transmission system does not get overloaded following respected contingencies. The IESO (formerly the Ontario Power Authority) stated their support for this project in a letter to Hydro One dated June 14, 2013.[5] The planned in-service date for this project is Q4 2017 at an estimated cost of $32 million. This is anticipated to be a transmission pool cost and LDCs are not expected to pay any contribution.

The station service supply to the York Energy Centre is currently supplied from Holland TS. However, a low-voltage breaker failure event at Holland TS or a double circuit 230 kV contingency can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source. The IESO intends to develop a plan to address this issue in the York Region IRRP update currently scheduled for 2017.

7.2.2 Mid-Term Need to Increase Transformation Capacity

Based on the growth forecast for the Northern York Area, the combined loading on Armitage TS and Holland TS will exceed their combined summer 10-Day LTR as early as 2023. There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. The IRRP indicated that the Claireville to Brown Hill circuits do not have sufficient capacity to fully supply another transformation station in Northern York Area after the Vaughan #4 MTS connection and Holland breakers project and therefore there is a long-term need to increase transmission capability to supply a new station. However, as noted in the York Region IRRP, under a low growth scenario in the long term, the demand in Northern York Area will stabilize to within the capacity of existing stations to beyond 2033.

7.2.2.1 Recommended Plan and Current Status

The York Region IRRP[1] identified a number of non-wires alternatives that may address or defer the need for further transformation capacity in Northern York Area. Such alternatives include CDM, DG, large generation and other local community initiatives. However, given that the need date for this area may be as early as 2023, it is necessary to identify a preferred alternative by 2018 that addresses both the transformation capacity need as well as the transmission capacity need. The working group expects to finalize a plan and recommendations to address these needs in an IRRP update currently scheduled for 2017.

7.3 Western Sub-Region

7.3.1 Load Restoration Need for the Claireville to Kleinburg Line

The three stations in this sub-region, Woodbridge TS, Vaughan #3 MTS and Kleinburg TS, are supplied by two radial 230kV circuits, V43 and V44, originating from Claireville TS. Inherent to radial configuration, the loss of these two circuits will interrupt supply to loads and consequently load restoration times as per the ORTAC[4] may not be met. This need was identified during the NA for this sub-region and also in the Northwest GTA IRRP[6] and it was subsequently recommended that this need be addressed in the IESO's GTA West bulk system planning initiative.

7.4 Long Term Future Transmission Corridor to the GTA North Region

The GTA West RIP recommended the establishment of a future-use transmission corridor, to address growth-related needs in the GTA West region. In addition to addressing needs in the GTA West region, development of an eastern portion of this corridor through the City of Vaughan is also a possible option that could address the long-term supply needs identified for York Region. It is therefore recommended that, in the development of the long-term plans for the GTA West and GTA North regions, consideration be given to coordinating solutions to meet the needs of both regions when assessing options for each region individually.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Vaughan Transformation Capacity (Near Term)
II	Northern York Area Load Security on B82V/B83V
III	Northern York Area Load Restoration on B82V/B83V
IV	Parkway to Claireville – Load Security on V71P/V75P
V	Parkway to Claireville – Load Restoration on V71P/V75P
VI	Markham Transformation Capacity (Mid-term)
VII	Vaughan Transformation Capacity (Mid-term)
VIII	Northern York Area Transformation Capacity (Mid-term)
IX	Kleinburg Tap – Load Restoration on V43/V44

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the needs are summarized in Table 8-2 below. Investments to address the needs where there is time to make a decision (Needs No. VI, VII, and VIII), will be reviewed and finalized in the next regional planning cycle. Need No. IX will be addressed in the IESO GTA West bulk system planning initiative.

Table 8-2: Regional Plans – Next Steps, Lead Responsibility and Planned In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Estimated Cost	Needs Mitigated
1	Vaughan #4 MTS	LDC to carry out the work	PowerStream	2017	$25M	I
2	Holland Breakers and SPS	Transmitter to carry out the work	Hydro One	2017	$32M	II, III
3	Parkway Belt Switches	Transmitter to carry out the work	Hydro One	2018	$4-6M	V

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs, the IRRP proposed that the process be updated in advance of the regular 5-year review schedule. The York Region IRRP is currently scheduled to be updated in 2017.

REFERENCES

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[5]. Hydro One, "OPA Letter – Initiating Near-Term Transmission Components of the York Region Integrated Regional Resource Plan," 14 June 2013.
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[6]. Independent Electricity System Operator, "Northwest Greater Toronto Area Integrated Regional Resource Plan", 28 April 2015
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

APPENDIX A: STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6 Kleinburg TS T1/T2 44	230/27.6 230/44	V43/V44
Vaughan MTS #3	230/27.6	V43/V44
Woodbridge TS T3/T5 27.6 Woodbridge TS T3/T5 44	230/27.6 230/44	V43/V44
Armitage TS T1/T2/T3/T4	230/44	B82V/B83V
Brown Hill TS T1/T2	230/44	B82V/B83V
Holland TS T1/T2	230/44	B82V/B83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1	230/27.6	P21R/P22R
Markham MTS #2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2/T3/T4	230/27.6	C35P/C36P
Markham MTS #4	230/27.6	P45/P46
Richmond Hill MTS #1	230/27.6	V71P/V75P
Richmond Hill MTS #2	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2/T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2	230/27.6	V71P/V75P

APPENDIX B: TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Brown Hill TS, Armitage TS and Holland TS	B82V/B83V	230
Claireville TS to Kleinburg TS, Vaughan MTS #3 and Woodbridge TS	V43/V44	230
Claireville TS to Vaughan MTS #1, Vaughan MTS #2, Richmond Hill MTS #1, Richmond Hill MTS #2, Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS and Markham MTS #4	P45/P46	230
Parkway TS to Markham MTS #2, Markham MTS #3, Cherrywood TS	C35P/C36P	230

APPENDIX C: DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type	Area/Region
Enersource Hydro Mississauga Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Brampton Networks Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Networks Inc. (Distribution)	Armitage TS	Tx	Northern York Area
	Brown Hill TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Woodbridge TS	Tx	Western Sub-Region
Newmarket-Tay Power Distribution Ltd.	Armitage TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
PowerStream Inc.	Armitage TS	Dx	Northern York Area
		Tx	Northern York Area
	Buttonville TS	Tx	Southern York Area
	Holland TS	Dx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Markham MTS #1	Tx	Southern York Area
	Markham MTS #2	Tx	Southern York Area
	Markham MTS #3	Tx	Southern York Area
	Markham MTS #4	Tx	Southern York Area
	Richmond Hill MTS #1	Tx	Southern York Area
	Richmond Hill MTS #2	Tx	Southern York Area
	Vaughan MTS #1	Tx	Southern York Area
	Vaughan MTS #2	Tx	Southern York Area
	Vaughan MTS #3	Tx	Western Sub-Region
	Woodbridge TS	Dx	Western Sub-Region
		Tx	Western Sub-Region
PowerStream Inc.[Barrie]	Holland TS	Dx	Northern York Area
Toronto Hydro Electric System Limited	Woodbridge TS	Dx	Western Sub-Region
Veridian Connections Inc.	Armitage TS	Dx	Northern York Area

APPENDIX D: GTA NORTH REGION LOAD FORECAST 2015-2025

Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Kleinburg 28 kV (BY)	97	54	56	58	59	63	64	66	69	70	70	70
Kleinburg 44 kV (EQ)	99	62	63	64	65	65	65	65	66	66	66	66
Vaughan 3 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Woodbridge 44 kV (EQ)	80	53	54	54	54	53	52	52	52	52	52	52
Woodbridge 28 kV (BY)	80	72	71	71	71	70	69	69	68	68	68	68
Holland TS 44 kV	168	136	138	142	144	145	146	149	152	154	156	158
Armitage TS 44 kV	317	294	299	306	312	314	317	324	330	336	338	344
Brown Hill TS 44 kV	184	74	76	79	81	83	85	88	90	93	95	98
Richmond Hill MTS 28 kV	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS 28 kV	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	153	0	24	47	69	83	97	119	140	160	170	185
Buttonville TS 28 kV	166	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS 28 kV	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS 28 kV	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS 28 kV	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS 28 kV	153	42	62	89	112	125	137	158	178	198	207	220

* LTR based on 0.9 power factor

APPENDIX E: LIST OF ACRONYMS

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

GTA West

REGIONAL INFRASTRUCTURE PLAN

January 25, 2016

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

With support from:

Company
Burlington Hydro Electric Inc.
Enersource Hydro Mississauga Inc.
Halton Hills Hydro Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Milton Hydro Distribution Inc.
Oakville Hydro Electricity Distribution Inc.

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DISCLAIMER

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

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

Working Group 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 RIP 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 RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP 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 RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

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

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

This RIP is the final phase of the regional planning process and it follows the completion of the Northwest GTA Integrated Regional Resource Plan ("IRRP") in April 2015; and the GTA West Southern Sub-Region's Needs Assessment ("NA") and Scoping Assessment ("SA") in May 2014 and September 2014, respectively.

This RIP provides a consolidated summary of needs and recommended plans for both the Northern Sub-Region and Southern Sub-Region that make up the GTA West Region.

The major infrastructure investments planned for the GTA West Region over the near and medium-term (2016-2025), identified in the various phases of the regional planning process, are given in the table below with anticipated in-service date and estimated cost. Several long-term needs beyond 2026 have been identified, and further assessments are currently underway as part of the IESO Bulk System Study.

No.	Project	I/S Date	Cost
1	Build new Halton Hills Hydro MTS	2018	$19M (1)
2	Build new Halton TS #2	2020	$29M (1)
3	Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	2018-2019	$5M
4	Upgrade (reconductor) circuits H29/H30 (2)	2023-2026	$6.5M

Notes:

(1) Excludes cost for distribution infrastructure

(2) The plan will be reviewed and finalized in the next regional planning cycle

The following needs will be considered in the scope of the Bulk System Study led by the IESO:

- Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity need;
- Radial supply to Halton TS (T38/T39B) circuit capacity need;
- Supply security and restoration to several load pockets in GTA West Region.

The IESO's Northwest GTA IRRP has identified that Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow by 849-1132 MW by 2031, as forecast by the Province "Places to Grow" program. A new electricity corridor will be required for additional transmission facilities required to meet this long-term need in the area. The RIP Working Group recommends further assessments to be carried out and complete technical details, layout of high voltage electricity infrastructure no later than Q4 2016. Following this, Environmental Approval and acquisition of land rights would be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

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1. INTRODUCTION

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

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

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The GTA West Region encompasses the municipalities of Brampton, southern Caledon, Halton Hills, Mississauga, Milton, and Oakville. The region includes the area roughly bordered geographically by Highway 27 to the north-east, Highway 427 to the south-east, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south, as shown in Figure 1-1.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV Trafalgar TS autotransformers, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. The summer 2015 peak load of the region was approximately 2900 MW.

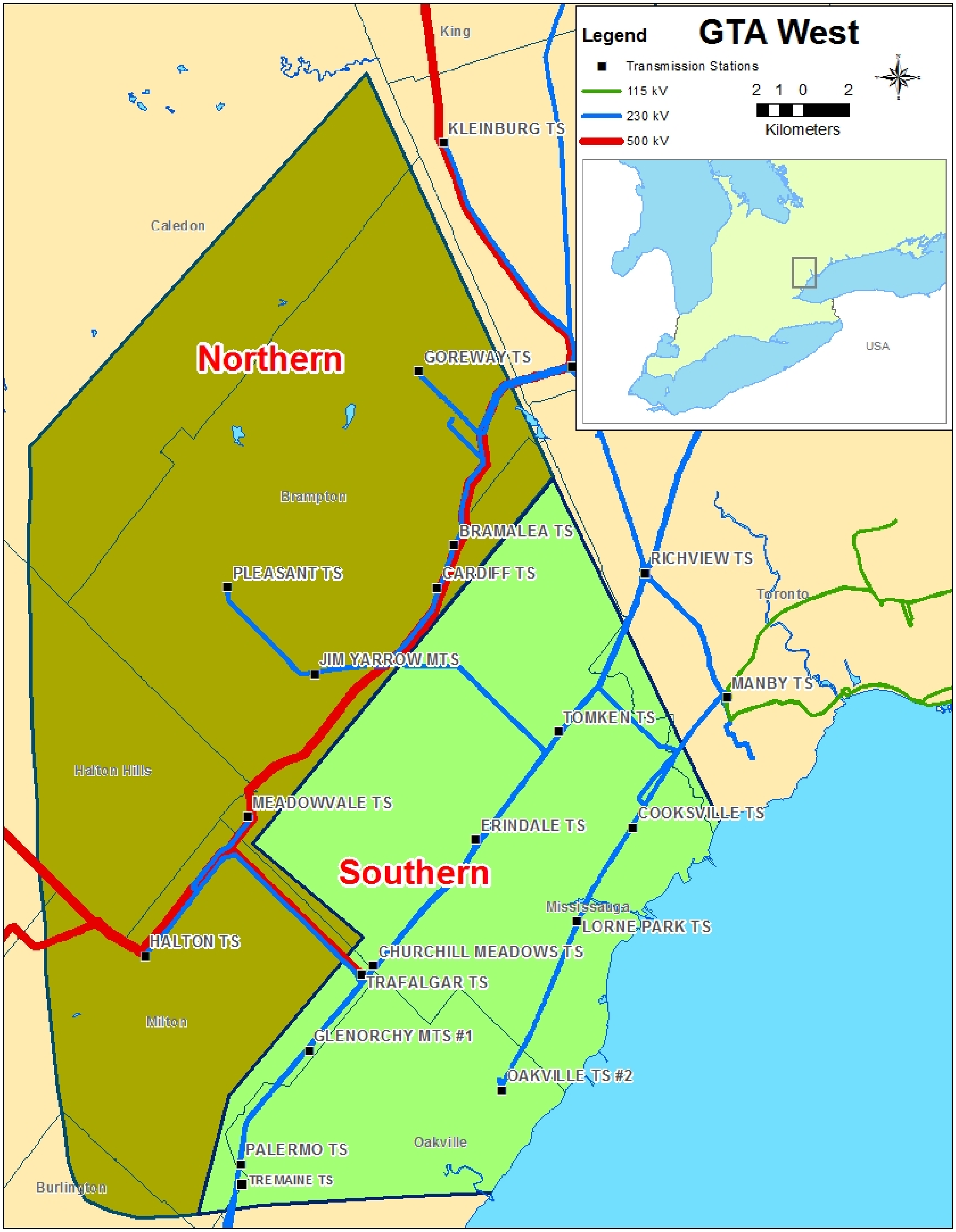

Figure 1-1 GTA West Region Map

1.1 Scope and Objectives

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

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

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management (“CDM”), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and wires plans to address these needs based on new and/or updated information;
- Develop a plan to address any longer terms needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] also referred to as Needs Screening

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

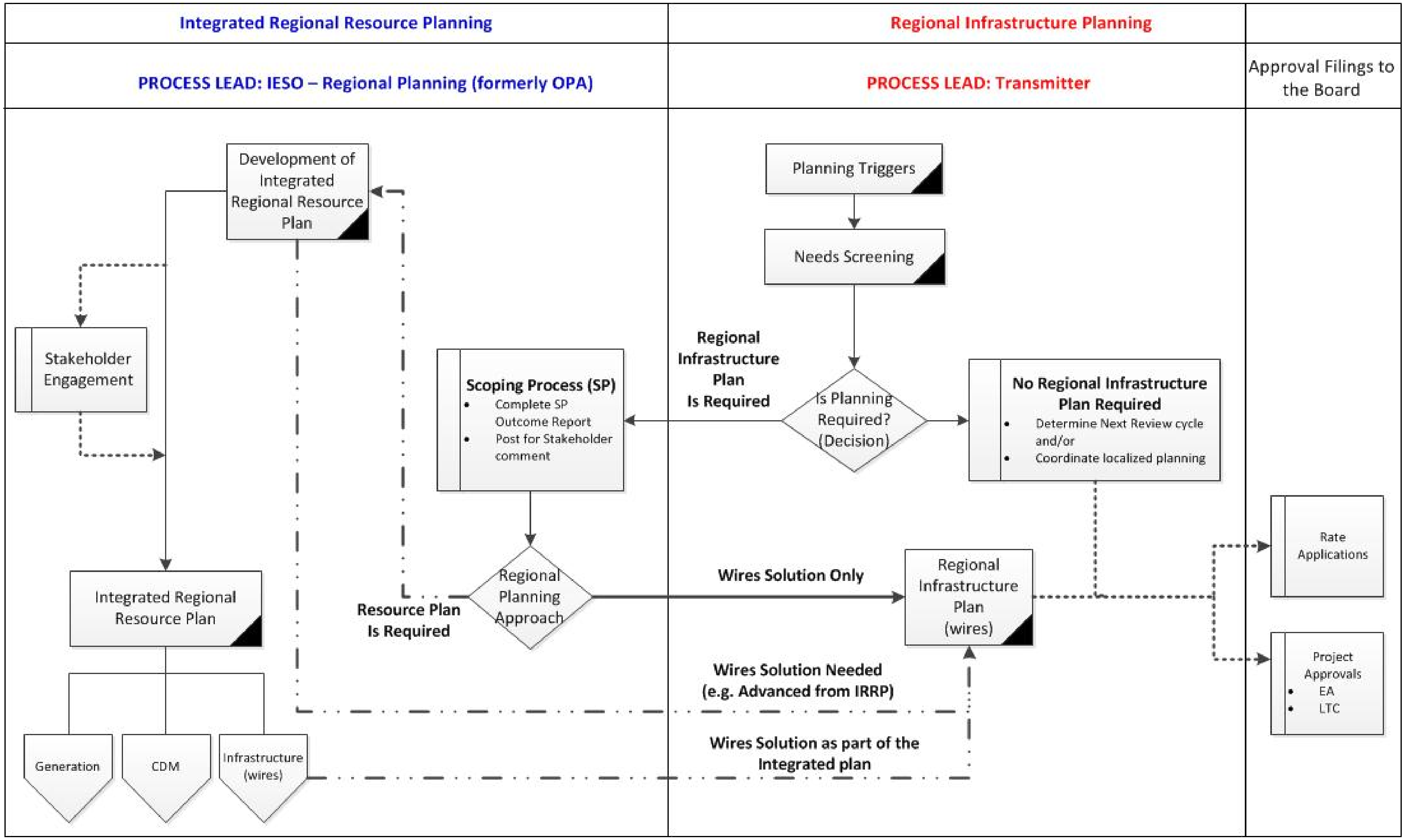

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

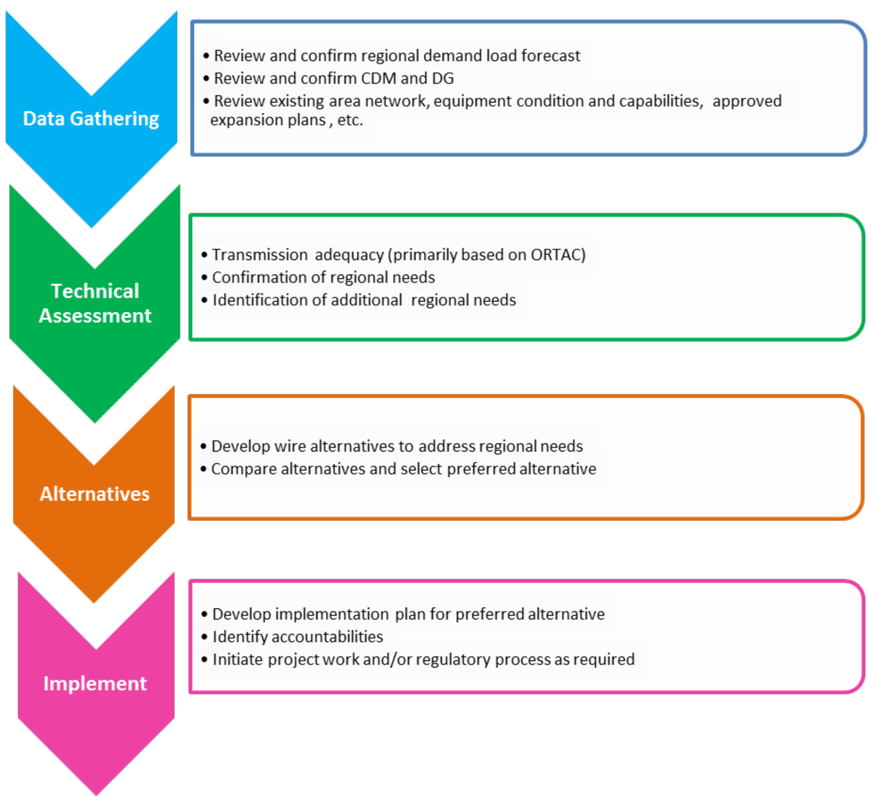

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA WEST REGION ENCOMPASSES THE MUNICIPALITIES OF BRAMPTON, SOUTHERN CALEDON, HALTON HILLS, MISSISSAUGA, MILTON, AND OAKVILLE. THE REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY HIGHWAY 27 TO THE NORTH-EAST, HIGHWAY 427 TO THE SOUTH-EAST, REGIONAL ROAD 25 TO THE WEST, KING STREET TO THE NORTH AND LAKE ONTARIO TO THE SOUTH.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. Local generation in the region includes the two gas fired plants: Sithe Goreway CGS (839 MW rated capacity) and TCE Halton Hills CGS (683 MW rated capacity). The summer 2015 regional coincidental peak load of the region is approximately 2900 MW.

LDCs supplied from electrical facilities in the GTA West Region are Burlington Hydro Electric Inc., Enersource Hydro Mississauga Inc., Halton Hills Hydro Inc., Hydro One Brampton Networks Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc., and Oakville Hydro Electricity Distribution Inc. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Northwest GTA IRRP report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Northern Sub-Region which included the 230 kV facilities in the northern part of Region. The May 2014 Southern GTA Needs Assessment report, prepared by Hydro One, considered the remainder of the GTA West Region.

For the purpose of regional planning, the GTA West Region is divided into Northern and Southern Sub-Regions. A single line diagram showing the electrical facilities of the GTA West Region, consisting of the two sub-regions, is shown in Figure 3-1. More details regarding transformer stations and transmission lines in the region are provided in Appendix A and B, respectively.

GTA West – Northern Sub-Region

The Northern Sub-Region covers the GTA West Region area north of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Claireville TS and Hurontario SS through seven 230/44 kV or 230/27.6kV step down transformer stations, local generation consist of the Sithe Goreway GS located in Brampton and the TransCanada Halton Hills GS located in Halton Hills, Generation is also connected to the LV buses of Bramalea TS in Brampton.

Enersource, Hydro One Brampton, Milton Hydro and Halton Hills Hydro are the three main Local Distribution Companies in the Sub-Region. They receive power at the step down transformer stations and distribute it to the end use customers.

The GTA West – Northern Sub-Region was identified as a “transitional” sub-region, as planning activities in this sub-region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. The Northwest GTA IRRP was completed for the Northern Sub-Region in April 2015.

GTA West – Southern Sub-Region

The Southern Sub-Region covers the GTA West Region area south of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Richview TS and Manby TS. There are a total of nine steps down 230/44 kV or 230/27.6 kV step down transformer stations serving the area customers.

Enersource Hydro Mississauga and Oakville Hydro are the main LDCs serving the GTA West - Southern Sub-Region. There is one large industrial customer (Ford Motor Company) in Oakville.

The NA and SA for the Southern Sub-Region were completed in May and September 2014, respectively. A Local Plan has also been developed in this sub-region to address a near-term station capacity need at Erindale TS, further discussed in Section 7.2.

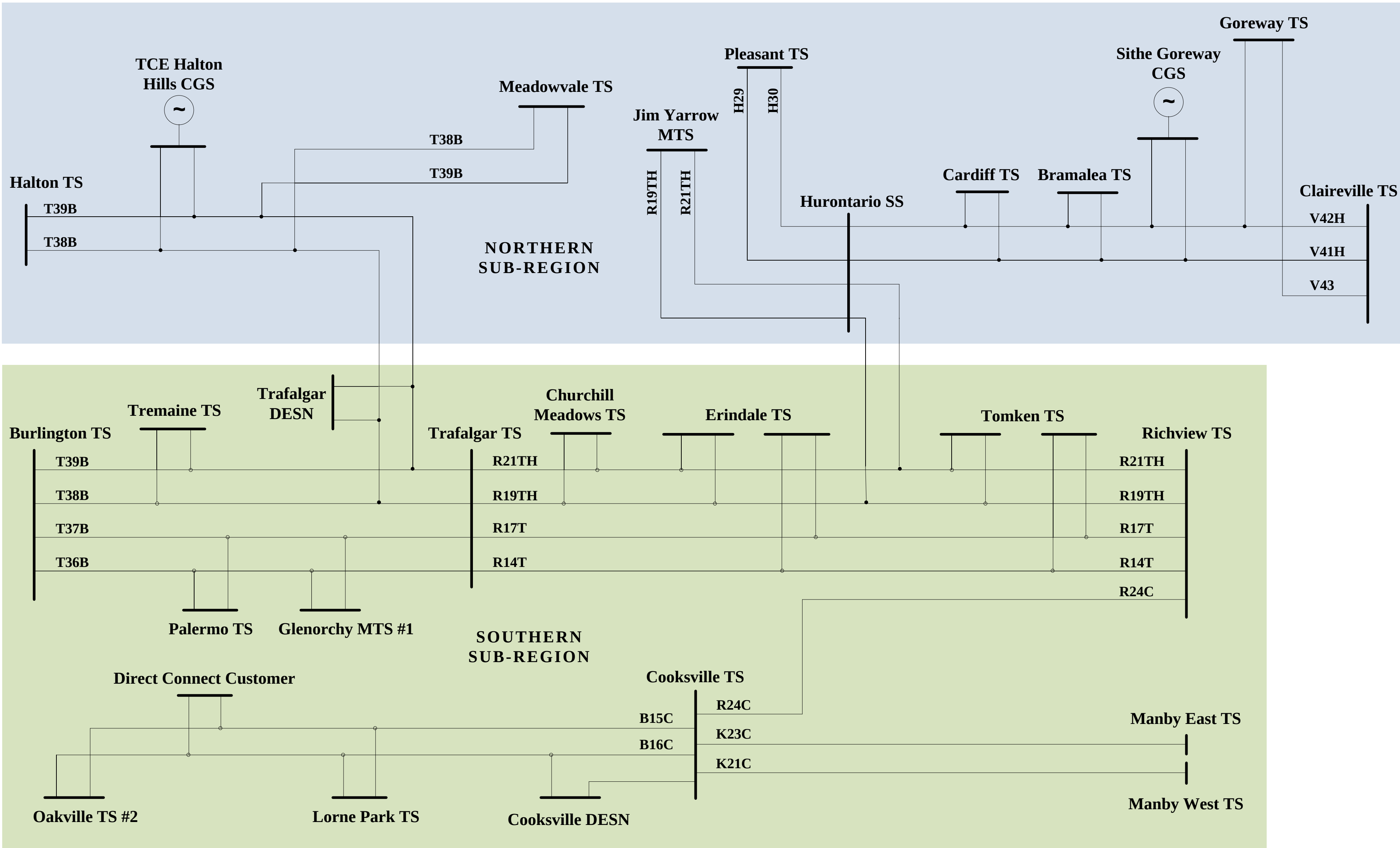

Figure 3-1 GTA West Region Single Line Diagram

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

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

A brief listing of those projects is given below:

- Cardiff TS (2005) – built a new step down transformer station consisting of two 50/83 MVA transformers in Brampton supplied from 230 kV circuits V41H and V42H. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Sithe Goreway CGS (2008) – connect a new 839 MW gas-fired combined cycle generation station in Brampton connected to 230 kV circuits V41H and V42H. This generation station provided necessary local power to supply the GTA West Region.
- Halton TS Shunt Capacitor - installed 43.2 MX of shunt capacitor banks at Halton TS 27.6 kV bus for voltage support (2009).
- Churchill Meadows TS (2010) – built a new step down transformer station consisting of two 75/125 MVA transformers in Mississauga supplied from 230 kV circuits R19TH and R21TH. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Hurontario SS and underground cable work - built a new switching station Hurontario SS, 4.2 km of double circuit 230 kV Line from Hurontario SS to Cardiff TS and 3.3 km of underground cable from Hurontario SS to Jim Yarrow TS (2010). The new switching station and associated line work connects the R19T/R21T circuits and the V42/V43H circuits to provide relief and improved reliability to Pleasant TS and Jim Yarrow MTS.
- Halton Hills CGS (2010) – connected a new 683 MW gas-fired combined cycle generation station in Halton Hills connected to 230 kV circuits T38B and T39B. This generation station provided necessary local power to supply the GTA West Region.
- Glenorchy MTS (2011) – connected new Oakville Hydro-owned Glenorchy MTS to 230 kV circuits T36B and T37B. This station provided additional load meeting capability to meet Oakville Hydro requirements
- Tremaine TS (2012) – built a new step down transformer station consisting of two 75/125 MVA transformers in Burlington supplied from 230 kV circuits T38B and T39B. This station provided additional load meeting capability to meet Burlington Hydro and Milton Hydro requirements.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA West Region is expected to grow at an average rate of approximately 0.8% annually from 2015 to 2025, and 0.5% from 2025 to 2035. The growth rate varies across the region ranging from 1.1% in the Northern Sub Region to 0.5% in the Southern Sub Region over the first 10 years. Longer term is a more uniform growth rate of 0.5% across both Northern and Southern Sub Regions. .

Figure 5-1 shows the GTA West Region load forecast from 2016 to 2035. The forecast shown is the regional coincidental forecast, representing the sum of the load in the area for the 17 step-down transformer stations at the time of the regional peak, and is used to determine any need for additional transmission reinforcements. The coincidental regional peak is forecast to increase from approximately 2900 MW in 2015 to 3300 MW in 2035. Non-coincident forecast for the individual stations in the region is available in Appendix A, and is used to determine any need for station capacity relief.

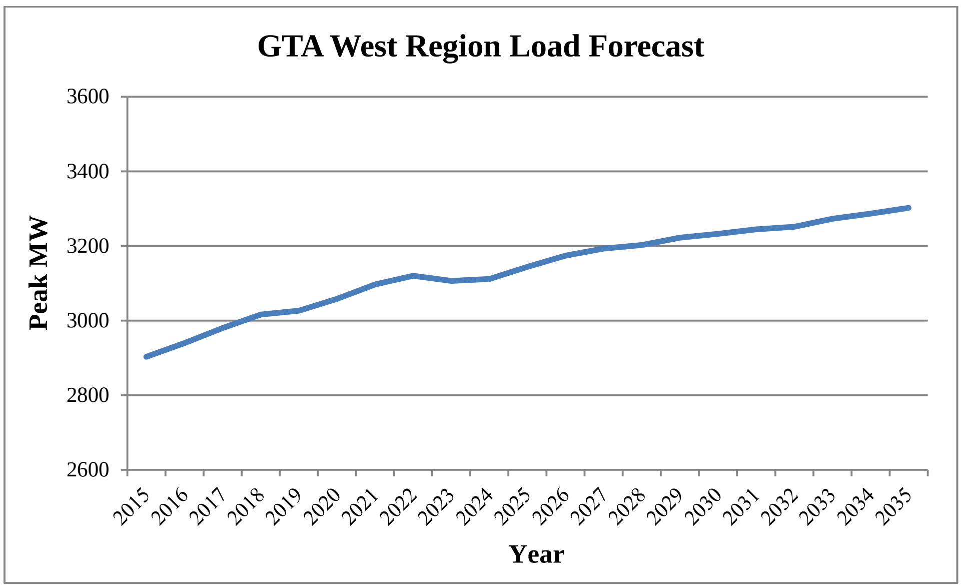

Figure 5-1 GTA West Region Extreme Weather Peak Load Forecast

The regional coincidental load forecast was developed by projecting the 2015 summer peak loads corrected for extreme weather, using the area station growth rates as per the 2015 IESO Northwest GTA IRRP and as per the 2014 Hydro One's Need Assessment Study for the GTA West Southern Sub-Region. The growth rate accounts for CDM measures and connected DG. Details on CDM and connected DG information used in this report are provided in the Northwest GTA IRRP and the Southern Sub-Region's NA, and not repeated in this report.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STATION FACILITIES SUPPLYING THE GTA WEST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE 2016-2025 PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA West Region. The findings of these assessments are input to the RIP. These assessments are:

1) The Northwest GTA Integrated Regional Resource Plan (IRRP), April 2015 [1]
2) The GTA West Southern Sub-Region's Needs Assessment (NA) Report, May 2014 [2]
3) The GTA West Southern Sub-Region's Scoping Assessment (SA) Report, September 2014 [3]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demand over the 2016-2025 period. These regional needs are summarized in Table 6-1. Table 6-1 also includes the longer-term needs (up to 2035) that have been identified in the Northern Sub-Region. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the GTA West Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review.

Table 6-1 Needs Identified in Previous Phases of the GTA West Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	Halton TS	2018-2020
	7.2	Erindale TS (T1/T2)	Today
Transmission Circuit Capacity	7.3	Richview x Trafalgar (R14T/R17T & R19TH/R21TH)	Within 5 years
	7.4	Radial Supply to Pleasant TS (H29/H30)	2023-2026
	7.5	Radial Supply to Halton TS (T38B/T39B)	2029+
Supply Security	7.6	Supply Security to Halton Radial Pocket (T38B/T39B)	2027
Supply Restoration	7.7	Supply Restoration in Northern Sub-Region [(1)]: - Halton Radial Pocket (T38B/T39B) - Pleasant Radial Pocket (H29/H30) - Cardiff/Bramalea Supply (V41H/V42H)	Today
	7.8	Supply Restoration in Southern Sub-Region: - West of Cooksville (B15C/B16C) - Richview x Trafalgar x Hurontario (R19TH/R21TH) - Richview x Trafalgar (R14T, R17T)	Today
Long-Term Growth	7.9	Pleasant TS (T1/T2) NWGTA Electricity Corridor	2026-2033+

(1) The Northwest GTA IRRP also identified an issue and need to assess "Kleinburg Radial Pocket" supply restoration. This need is being assessed as part of the IESO led Bulk System Study and is not part of this RIP.

6.1 230 kV Transmission Facilities

All 230 kV transmission facilities in the GTA West Region, with the exception of Hurontario SS to Pleasant TS 230 kV circuits H29 and H30 are classified as part of the Bulk Electricity System (BES). A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-1):

1. Claireville TS to Hurontario SS (230 kV Circuits V41H, V42H, V43) – Supply Bramalea TS, Cardiff TS, and Goreway TS
2. Hurontario SS to Pleasant TS (230 kV Circuits H29, H30) – Supply Pleasant TS
3. Trafalgar TS to Burlington TS, radial tap to Halton TS and Meadowvale TS (230 kV Circuits T38B, T39B) – Supply Halton TS, Meadowvale TS, and Trafalgar DESN
4. Trafalgar TS to Burlington TS (230 kV Circuits T36B, T37B, T38B, T39B) – Supply Glenorchy MTS #1, Palermo TS, and Tremaine TS
5. Richview TS to Trafalgar TS (230 kV Circuits R14T, R17T) – Supply Erindale TS and Tomken TS
6. Richview TS to Trafalgar TS, with tap to Hurontario SS (230 kV Circuits R19TH, R21TH) – Supply Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, and Tomken TS
7. Richview TS and Manby TS to Cooksville TS (230 kV Circuits R24C, K21C, K23C, B15C, B16C) – Supply Cooksville DESN, Ford Oakville CTS, Lorne Park TS, and Oakville TS #2

Based on current forecast station loadings and bulk transfers, the H29/H30 circuits will require reinforcement by 2023-2026. The H29/H30 upgrade will be addressed by Hydro One based on the recommendation stemming from the Northwest GTA IRRP led by the IESO. The Trafalgar to Richview 230 kV circuits (R14T/R17T) will require reinforcement in the near term based on GTA West Southern Sub-Region's NA. This need will be further assessed in the IESO led Bulk System Study.

6.2 500/230 kV Transformation Facilities

All loads are supplied from the 230 kV transmissions system. The primary source of 230 kV supply is the 500/230 kV autotransformers at Trafalgar TS and Claireville TS, as well as 230 kV supply from Burlington TS. Additional support is provided from the 230 kV generation facilities at Halton Hills CGS and Sithe Goreway CGS. Based on the long term forecast in the Northwest GTA IRRP, Trafalgar TS and Claireville TS may require relief in the next 10 years. This need will be studied under the IESO led Bulk System Study.

6.3 Step-Down Transformation Facilities

There are a total of sixteen step-down transformer stations in the GTA West Region. Based on the local station load forecast, Halton TS and Erindale TS would require station capacity relief in the near term, as shown in Table 6-2.

Table 6-2 Step-Down Transformer Stations Requiring Relief

Station	Capacity (MW)	2015 Loading (MW)	Need Date
Halton TS	185.9	176.4	2018
Erindale TS (T1/T2)	181.3	208.3	Now
Pleasant TS (T1/T2)	148.1	124.8	2026-2033 (1)

(1) 2026 under the “Higher Growth” scenario, while 2033 under the “Expected Growth” scenario. Please refer to Northwest GTA IRRP [1]

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES OPTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE GTA WEST REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NORTHWEST GTA IRRP AND THE NA FOR THE GTA WEST SOUTHERN SUB-REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 Halton TS Station Capacity

7.1.1 Description

Halton TS supplies Halton Hills Hydro through 3 feeders and Milton Hydro through 9 feeders at the station. As the load in Halton Hills and Milton continues to grow, the peak load at Halton TS is expected to exceed the station peak load by 2018.

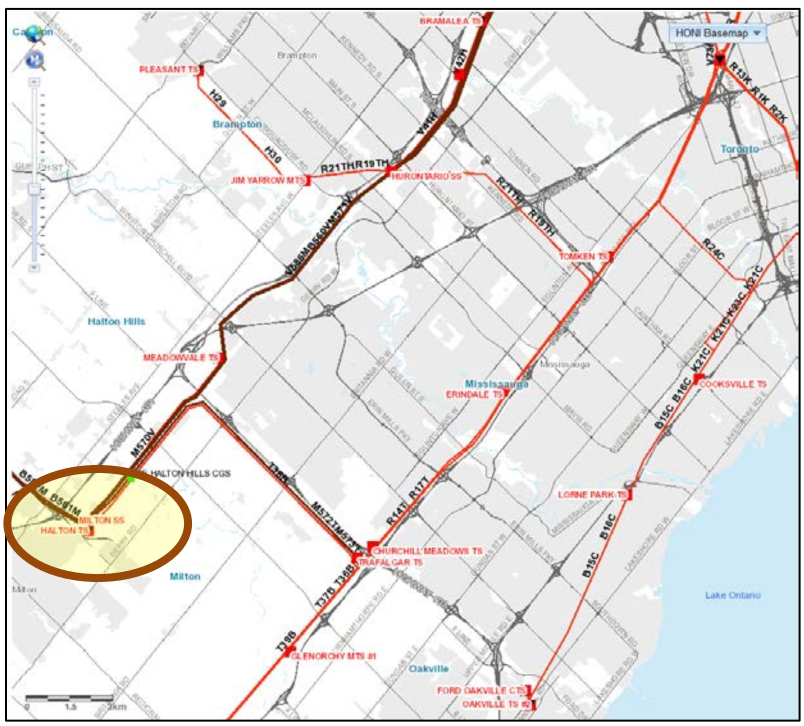

Figure 7-1 Halton TS and Surrounding Areas

7.1.2 Recommended Plan and Current Status

The recommendation of the IRRP is to build two new step-down stations: one to provide supply for Halton Hills Hydro loads and second to supply Milton Hydro load. The Halton Hills Hydro station is expected to be required in 2018, while the Milton Hydro station is expected to be required in 2020.

The IRRP recommends that Halton Hills Hydro proceed to gain the necessary approvals to construct, own, and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018. Halton Hills Hydro has started a Request for Proposal for the work to construct Halton Hills MTS. The station will consists of two 50/83 MVA transformers with capacity to connect eight distribution feeders. The existing Halton Hills CGS will be expanded to accommodate the HV connection of Halton Hills MTS. There are no transmitter costs for this station. The expected in-service date is spring of 2018. The cost for this station is estimated to be $19 million.

The IRRP recommends Hydro One to initiate engineering work for the development of Halton TS #2 in 2017 (3 year lead-time), at the site of the existing Halton TS, with a tentative in-service date of 2020. The Halton Hills TS #2 will consist of two 75/125 MVA transformers with capacity to connect eight distribution feeders. It will tap to circuits T38B and T39B. The cost for Hydro One to build Halton TS #2 is estimated to be $29 million.

7.2 Erindale TS (T1/T2) Station Capacity

7.2.1 Description

Erindale TS solely supplies Enersource Hydro Mississauga Inc. The existing Erindale TS (T1/T2) DESN load currently exceeds the normal supply capacity. However, there is extra capacity available in the area's 44 kV system that can be utilized by building a step down (44/27.6 kV) distribution station.

Options for providing the required relief were investigated in Local Planning for Erindale TS T1/T2 DESN Capacity Relief [4]. As per the Local Plan, Hydro One and Enersource agreed that this is primarily a distribution planning issue that will involve planning and building a new DS by Enersource to utilize the extra 44 kV station capacity in the area.

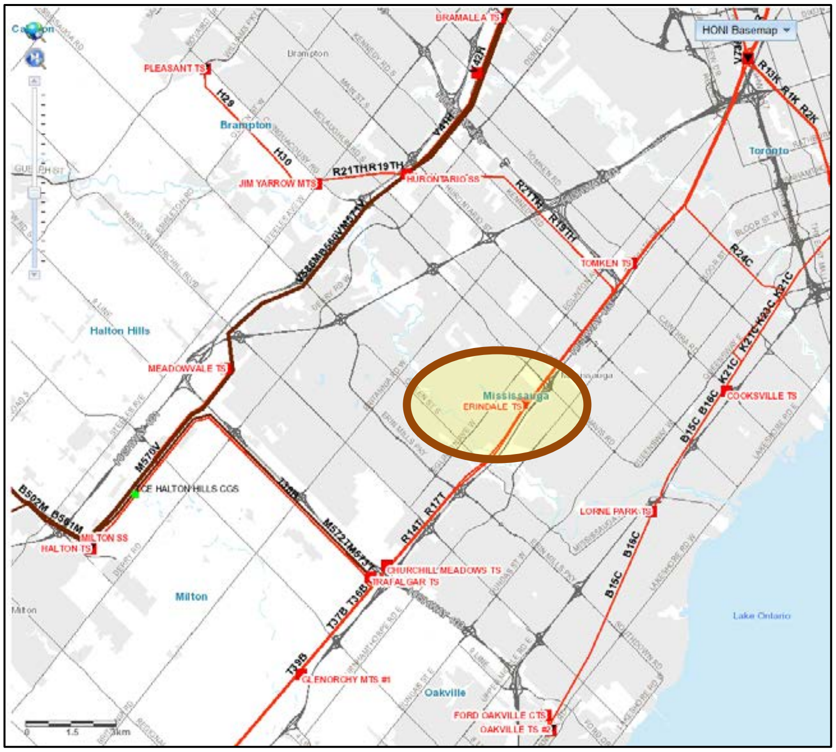

Figure 7-2 Erindale TS and Surrounding Areas

7.2.2 Recommended Plan and Current Status

The proposed DS ("Mini-Britannia MS") is planned to be supplied from Churchill Meadows TS (44 kV system) and provide additional capacity to feed the 27.6 kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on 44 kV system via Churchill Meadows TS.

At completion, the substation will house two power transformers (40 MVA capacity), two high voltage switchgears and two low voltage switchgears that will deliver power via four 27.6 kV feeders.

This option is expected to cost $5 million. Under this option, Enersource will build the new DS, own it and recover the costs through the distribution rates. The expected in-service date for the DS is 2018-2019.

7.3 Richview x Trafalgar Transmission Circuit Capacity

7.3.1 Description

As identified in the GTA West Southern Sub-Region's NA, with a single-circuit contingency and high Flow East Towards Toronto (FETT) interface flows, loading on the Richview TS to Trafalgar TS circuits (R14T, R17T, R19TH, R21TH) exceeded their summer long-term emergency ratings in the near-term.

7.3.2 Recommended Plan and Current Status

As these circuits are part of the Bulk Electric System, this need is being further assessed in the IESO-led bulk power system planning.

7.4 Radial Supply to Pleasant TS Transmission Circuit Capacity

7.4.1 Description

Pleasant TS consists of 3 DESNs supplied by 230 kV H29/H30 circuits. Due to growth in load forecasted at Pleasant TS, these circuits are expected to reach their thermal capacity by 2023 at the earliest.

The IRRP process, completed in April 2015, identified the need, discussed alternatives, and recommended a solution to resolve this need.

7.4.2 Recommended Plan and Current Status

The existing conductors used for 230kV circuits H29/H30 going to Pleasant TS are 795.0 kcmil ACSR 26/7 with summer long term emergency rating of 1090 A (at 127°C). They extend 8.5km north from Hurontario SS to Pleasant TS. Based on the study conducted in the Northwest GTA IRRP, this rating limits the maximum load-carrying capacity to approximately 417 MW of load at Pleasant TS.

Preliminary feasibility study shows that the existing towers can support larger conductors. The recommended new conductors would be 1192.5 kcmil ACSR 54/19 with summer long term emergency rating of approximately 1400 A (at 127°C). As per the load flow study conducted in the IRRP, this would supply over 500 MW of load at Pleasant TS. The estimated budgetary cost of this upgrade is about $6.5 million.

The Working Group recommends regularly monitoring the actual load growth and reassessing this issue during the next regional planning cycle.

7.5 Radial Supply to Halton TS Transmission Circuit Capacity

7.5.1 Description

The Northwest GTA IRRP study identified that the thermal capacity of supply circuit to Halton TS from Trafalgar TS to Burlington TS (T38B/T39B) may be exceeded with a single-circuit contingency and Halton Hills GS out of service in the mid-term. However, under this scenario, the ORTAC permits up to 150 MW of load shedding to prevent system overloads. With this control action in place, this need is observed in the long-term in 2029 at the earliest.

7.5.2 Recommended Plan and Current Status

As per the IRRP recommendation, this regional need is being further assessed in the IESO-led bulk power system planning.

7.6 Supply Security to Halton Radial Pocket (T38B/T39B)

7.6.1 Description

As the load connected to T38B/T39B continues to grow, it is expected by 2027 the Halton Radial Pocket will not be able to meet the ORTAC supply security criteria, which states that no more than 600 MW can be interrupted due to a loss of two major power system elements, as shown in Table 7-1.

Table 7-1 Halton Radial Pocket Load Forecast

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Halton Radial Pocket Load (MW)	463	471	482	490	491	492	503	512	562	571	585	598	**609**

7.6.2 Recommended Plan and Current Status

The Working Group recommends that the bulk power system study led by IESO account for this supply security issue on T38B/T39B in their planning process.

7.7 Supply Restoration in Northern Sub-Region

The Northwest GTA IRRP study identified that the following circuits are currently at risk of not meeting the supply security and restoration criteria:

Table 7-2 Supply Restoration Need in Northern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)
Halton Radial Pocket • Tremaine • Trafalgar DESN • Meadowvale • Halton • Halton Hills Hydro MTS (1) • Halton #2 (1) Supply: T38B/T39B	463	146	**67**
Pleasant Radial Pocket • Pleasant DESNs Supply: H29/H30	359	52	**57**
Bramalea/Cardiff Supply • Bramalea DESNs • Cardiff Supply: V41H/V42H	456	140	**66**

(1) Available 30-min restoration through emergency distribution load transfer following the loss of transmission supply (based on IRRP)
(2) Calculated as follows: Actual Load minus 250 MW minus 30minRestorationCapability. 250 MW is the maximum amount of load not restored within 30-min following loss of two elements.
(3) Halton Hills Hydro MTS and Halton TS #2 are expected to be in-service in 2018 and 2020.

The Northwest GTA IRRP also identified "Kleinburg Radial Pocket" supply restoration need. However, this need will be discussed in more details in the IESO's Bulk System Studies.

As per the IRRP recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

It is expected that with new increased forecasted load at Tremaine TS provided by Milton Hydro and Burlington Hydro, circuitsT38B/T39B Burlington TS to Trafalgar TS will experience higher power flow, and the need date may be moved closer. Therefore, the Working Group recommends that the bulk power system study led by IESO account for this increased flow on T38B/T39B in their planning process.

7.8 Supply Restoration in Southern Sub-Region

The GTA West Southern Sub-Region SA identified that the following circuits are at a risk of not meeting the supply security and restoration criteria in the medium term to long term time frame:

Table 7-3 Supply Restoration Need in Southern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)	Load (MW) That Can Be Restored Within 4-hour (1)	4-hour Restoration Shortfall (MW) (3)
West of Cooksville • Oakville #2 • Ford Oakville • Lorne Park Supply: B15C/B16C	304	46	**8**	110	**44**
Richview x Trafalgar x Hurontario • Churchill Meadows • Erindale T5/T6 • Tomken T3/T4 • Jim Yarrow Supply: R19TH/R21TH	555	165	**140**	465	None
Richview x Trafalgar • Erindale T1/T2 • Erindale T3/T4 • Tomken T1/T2 Supply: R14T/R17T	498	115	**133**	390	None

As per the Southern Sub-Region's SA recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

7.9 Long-Term Growth & NWGTA Electricity Corridor Need

Growth projections in the Ontario Governments - Growth Plan for the Greater Golden Horseshoe [5] indicates that the population in Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow significantly over the 20 years period, from 930,000 people in 2011 to 1.5 million people in 2031. Growth plan of this magnitude translates to an overall electrical demand of approximately 849 to 1132 MW by 2031 [1]. Supply electrical demand related to this growth will require new transmission and distribution infrastructure in the area because current electricity infrastructure in the area is limited and at its capacity. Planning and Environmental Approval for a proposed new 400 series Highway, extending from Highway 400 to the Highway 401/407 ETR interchange, has been paused by the Ministry of Transportation. However, opportunities for multi-use transportation/ electricity transmission line corridor must be investigated as new transportation and electricity plans for the area are developed, to maintain consistency with direction outlined in the Provincial Policy Statement.

Existing electricity supply to new developments in the area is technically limited by transmission line and transformer station supply capacity. In addition, there are customer service quality concerns, such as reliability performance and low voltage levels on the LDC's distribution feeders due to the long distance between the locations of new development and existing transformer stations.

Based on the latest load forecast, electrical load at Pleasant TS, which supplies Brampton, is anticipated to exceed its station capacity as early as 2026 [1]. As the result, new station will be required to meet growing electrical needs.

Since a typical 75/125 MVA 230 kV step-down transformer station is capable of supplying up to 170 MW of load, up to 6 new stations in strategic locations could be required to effectively meet load growth in the area over the next 10-20 years. In order to provide adequate supply to these new step-down stations, new 230 kV transmission lines will be required within the general vicinity of the area's load growth centers.

In addition to the need for supply capacity to meet growth, several locations are at risk for not meeting ORTAC criteria following the loss of two transmission elements: Halton radial pocket, Pleasant radial pocket, Bramalea/Cardiff supply, and Kleinburg radial pocket. These needs should also be studied and addressed in a coordinated manner to develop optimal solutions for both GTA North and GTA West Region. As a result, a high degree of integration will be required between regional planning in the two adjacent regions going forward.

Siting a new transmission corridor in the area would provide an alternate supply route to enable continued electrical service when other lines are out of service. Currently it is estimated that over 250 MW of load will not be restored within the timelines prescribed by the criteria. The situation and risk will continue to worsen with continued growth and load will be at higher risk of prolonged power outages following major system contingencies.

An important first phase for providing the required transmission capacity is to identify land / right of ways, which can accommodate economical overhead transmission lines. This includes completing an Environmental Approval followed with an application to the OEB for Leave to Construct (Section 92). The EA process and acquisition of land rights process may take up to five years. Allowing the area to develop without identifying the electricity corridor in municipal plans and not acquiring land rights for transmission corridor now would be significantly arduous after municipal and community development has already taken place without consideration of electricity needs. Identifying and preserving rights-of-way ahead of the forecasted need will help rate payers and municipalities avoid cost associated with underground cables in the future, which is significantly more costly ranging from 5 to 10 times higher than overhead lines.

Continued load growth throughout the GTA, and changing generation patterns across the province, are expected to stress the bulk transmission system's capacity. One option for addressing this need is the addition of a major new 500/230 kV supply point at the existing Milton SS. This new 500/230 kV supply point will provide an additional source to the local network and would need to be supplemented with the incorporation of new 230 kV lines and reconfiguration of the 230 kV system in the area. A new corridor providing new 230 kV transmission lines connecting Milton TS in GTA West and Kleinburg TS in GTA North will allow for better overall bulk system performance in the long-term.

Existing projections of electricity corridor needs can be as early as 2025. The RIP concludes that based on growth projections outlined in the Growth Plan for the Greater Golden Horseshoe [5] a new electricity corridor will be ultimately required to provide additional transmission capacity to meet load growth; provide alternate supply route to various locations to meet restoration criteria; and improve bulk electricity transfer capability.

The RIP Working Group recommends that:

a) The required transmission corridor be identified within the appropriate Regional and Municipal Official Planning documents.

b) Hydro One, the IESO and LDCs undertake immediate action to further assess the location and pace of growth, as well as the related high voltage electrical facilities required for inclusion in a future electricity infrastructure plan. The plan should include but not limited to details with respect to conceptual layout of transmission lines, line terminations, switching stations and the number and approximate location of step-down transformer stations.

c) Following this, Environmental Approval and acquisition of land rights should be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

d) Hydro One, the IESO and LDCs should complete the assessment, technical details, layout of high voltage electricity infrastructure no later than Q4 2016.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA WEST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Halton TS station capacity
II	Erindale TS T1/T2 station capacity
III	Radial supply to Pleasant TS (H29/H30) circuit capacity
IV	Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity
V	Radial supply to Halton TS (T38B/T39B) circuit capacity
VI	• Supply security to Halton Radial Pocket • Supply restoration to Halton Radial Pocket, Pleasant Radial Pocket, and Bramalea/Cardiff Supply load pockets • Supply restoration to West of Cooksville, Richview x Trafalgar, and Richview x Trafalgar x Hurontario load pockets
VII	Long term need for a new NWGTA electricity transmission corridor

Next steps, lead responsibility, and timeframes for implementing the wires solutions are summarized in the Table 8-2 below. Investments to address the long-term need where there is time to make a decision (Need III) will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans - Next Steps, Lead Responsibility and Plan In-Service Dates

Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
Build new Halton Hills Hydro MTS	LDC to carry out the work	Halton Hills Hydro	2018	$19M (1)	I
Build new Halton TS #2	Transmitter to carry out the work	Hydro One	2020	$29M (1)	I
Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	LDC to carry out the work	Enersource	2018-2019	$5M	II
Upgrade (reconductor) circuits H29/H30 (2)	Transmitter to carry out the work, and monitor growth	Hydro One	2023-2026	$6.5M	III
• R14T/R17T & R19TH/R21TH circuit capacity need • T38/T39B circuit capacity need • Supply security and restoration need	IESO to carry out Bulk System Study	IESO	TBD	TBD	IV, V, VI
Need for a new transmission corridor in NWGTA	Working Group to complete assessments, technical details & layout by Q4 2016	Hydro One, IESO, LDCs	TBD	TBD	VII

Notes:

(1) Excludes cost for distribution infrastructures
(2) The plan will be reviewed and finalized in the next regional planning cycle

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator. "Northwest GTA Integrated Regional Resource Plan". April 28, 2015. http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

[2] GTA West Southern Sub-Region Study Team. "Needs Screening Report – GTA West Southern Sub-Region". May 30, 2014. http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Needs%20Assessment%20Report%20-%20GTA%20West%20-%20Southern%20Subregion.pdf

[3] GTA West Southern Sub-Region Study Team. "GTA West Southern Sub-Region Scoping Assessment Outcome Report". September 19, 2014. http://www.ieso.ca/Documents/Regional-Planning/GTA_West/Scoping-Assessment-Outcome-Report-September-2014.pdf

[4] Hydro One Networks Inc., Enersource Hydro Mississauga Inc. "Local Planning Report – Erindale TS T1/T2 DESN Capacity Relief – GTA West Southern Sub-Region". July 9, 2015. http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Local%20Planning%20Report%20-%20Erindale%20TS%20Capacity%20-%209_July_2015.pdf

[5] Ministry of Infrastructure. Places to Grow: "Growth Plan for the Greater Golden Horseshoe, 2006". Office Consolidation June 2013. https://placestogrow.ca/content/ggh/2013-06-10-Growth-Plan-for-the-GGH-EN.pdf

Appendix A. Stations in the GTA West Region

Station (DESN)	Voltage (kV)	Supply Circuit
Halton TS	230/27.6	T38B/T39B
Meadowvale TS	230/44	T38B/T39B
Jim Yarrow MTS	230/27.6	R19TH/R21TH
Pleasant TS (T1/T2)	230/44	H29/H30
Pleasant TS (T5/T6)	230/27.6	H29/H30
Pleasant TS (T7/T8)	230/27.6	H29/H30
Cardiff TS	230/27.6	V41H/V42H
Bramalea TS (T1/T2)	230/27.6	V41H/V42H
Bramalea TS (T3/T4)	230/44	V41H/V42H
Bramalea TS (T5/T6)	230/44	V41H/V42H
Goreway TS (T1/T2)	230/27.6	V42H/V43
Goreway TS (T5/T6)	230/27.6	V42H/V43
Goreway TS (T4)	230/44	V42H/V43
Tremaine TS	230/27.6	T38B/T39B
Trafalgar TS	230/27.6	T38B/T39B
Palermo TS	230/27.6	T36B/T37B
Glenorchy MTS #1	230/27.6	T36B/T37B
Churchill Meadows TS	230/44	R19TH/R21TH
Erindale TS (T1/T2)	230/27.6	R14T/R17T
Erindale TS (T3/T4)	230/44	R14T/R17T
Erindale TS (T5/T6)	230/44	R19TH/R21TH
Tomken TS (T1/T2)	230/44	R14T/R17T
Tomken TS (T3/T4)	230/44	R19TH/R21TH
Oakville TS #2	230/27.6	B15C/B16C
Lorne Park TS	230/27.6	B15C/B16C
Cooksville TS (T1/T2)	230/27.6	B16C
Cooksville TS (T3/T4)	230/27.6	B16C

Appendix B. Transmission Lines in the GTA West Region

Location	Circuit Designations	Voltage (kV)
Hurontario SS to Pleasant TS	H29, H30	230
Richview TS to Trafalgar TS	R14T, R17T	230
Richview TS to Trafalgar TS & Hurontario SS	R19TH, R21TH	230
Trafalgar TS to Burlington TS	T36B, T37B, T38B, T39B	230
Claireville TS to Hurontario SS	V41H, V42H	230
Claireville TS to Kleinburg TS (1)	V43	230
Cooksville TS to Oakville TS	B15C, B16C	230
Manby TS to Cooksville TS	K21C, K23C	230
Richview TS to Cooksville TS	R24C	230

(1) Only V43 sections that supplies Goreway TS is included

Appendix C. Distributors in the GTA West Region

Distributor Name	Station Name	Connection Type
Burlington Hydro Inc.	Palermo TS	Tx
	Tremaine TS	Tx
Enersource Hydro Mississauga Inc.	Bramalea TS	Dx
		Tx
	Cardiff TS	Tx
	Churchill Meadows TS	Tx
	Cooksville TS	Tx
	Erindale TS	Tx
	Lorne Park TS	Tx
	Meadowvale TS	Tx
	Oakville TS #2	Dx
	Tomken TS	Tx
Halton Hills Hydro Inc.	Halton TS	Dx
		Tx
	Pleasant TS	Dx
Hydro One Brampton Networks Inc.	Bramalea TS	Tx
	Goreway TS	Tx
	Jim Yarrow MTS	Tx
	Pleasant TS	Tx
Hydro One Networks Inc. (Distribution)	Bramalea TS	Tx
	Halton TS	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Pleasant TS	Tx
	Trafalgar TS	Tx
Milton Hydro Distribution Inc.	Halton TS	Tx
	Palermo TS	Dx
	Tremaine TS	Tx
Oakville Hydro Electricity Distribution Inc.	Glenorchy MTS #1	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Trafalgar TS	Dx

Appendix D. GTA West Stations Load Forecast

GTA West Non-Coincident Stations Load Forecast (MW)

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bramalea TS T1/T2	N	188.4	124.6	124.7	124.3	124.2	122.0	122.7	122.7	122.5	121.7	119.9	119.2	121.4	121.0	119.7	119.6	118.3	118.2	118.1	119.0	119.3	119.5
Bramalea TS T3/T4	N	105.7	99.5	99.4	99.3	99.0	97.5	97.2	97.0	96.7	96.0	94.8	94.4	94.8	94.2	93.3	93.1	92.3	91.9	91.6	92.1	92.0	91.9
Bramalea TS T5/T6	N	159.1	122.9	123.0	122.7	122.6	120.3	120.9	120.7	120.4	119.4	117.4	116.7	118.2	117.6	116.2	116.0	114.6	114.4	114.3	115.2	115.4	115.6
Cardiff TS T1/T2	N	113.5	108.8	109.1	109.8	110.0	109.4	108.8	109.2	109.4	109.6	109.3	109.6	109.8	109.8	109.6	109.9	110.1	110.0	110.0	111.0	111.3	111.6
Goreway TS T1/T2	N	184.0	35.5	39.7	41.8	44.8	44.5	49.7	52.6	55.0	55.0	54.2	58.9	62.0	63.4	62.5	63.1	62.4	62.0	61.9	63.7	64.1	64.6
Goreway TS T4	N	84.0	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Goreway TS T5/T6	N	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2
Halton Hills Hydro MTS	N	97.1	0.0	0.0	0.0	3.5	8.1	11.7	15.8	19.7	23.5	26.9	32.2	37.2	42.1	46.7	51.7	51.9	51.9	52.0	52.9	53.2	53.6
Halton TS T3/T4	N	185.9	176.4	179.1	184.4	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Halton TS #2	N	146.3	0.0	0.0	0.0	0.0	0.0	2.3	11.0	18.5	66.2	72.5	80.2	87.2	93.5	99.0	105.9	112.1	118.2	116.9	117.9	120.0	122.1
Jim Yarrow MTS T1/T2	N	156.6	132.3	134.9	136.3	138.3	138.3	142.6	144.6	146.1	146.1	145.2	148.1	149.6	149.8	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Meadowvale TS T1/T2	N	180.8	128.7	127.1	126.0	124.4	121.9	119.4	118.1	116.5	115.0	113.0	111.6	110.1	108.5	106.7	105.4	104.0	102.4	100.9	100.2	99.0	97.8
Pleasant TS T1/T2	N	148.1	124.8	127.5	131.2	134.3	134.3	135.0	136.3	137.6	138.5	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4	150.0	151.6
Pleasant TS T5/T6	N	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3
Pleasant TS T7/T8	N	187.7	45.1	54.5	56.8	57.9	57.9	63.5	66.7	69.3	70.0	68.0	74.7	77.8	79.4	77.0	77.0	76.7	76.1	75.8	79.0	79.8	80.6

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Churchill Meadows TS T1/T2	**S**	**172.5**	101.6	102.0	102.3	102.2	101.3	100.5	100.5	100.4	100.2	100.0	99.9	99.7	99.5	99.3	99.2	99.0	98.8	98.7	98.5	98.3	98.1
Cooksville TS T3/T4	**S**	**119.8**	52.9	52.4	53.3	54.2	54.5	54.8	55.6	56.5	57.5	58.1	58.7	59.3	60.0	60.6	61.2	61.9	62.5	63.2	63.8	64.5	65.2
Cooksville TS T1/T2	**S**	**119.7**	49.8	49.4	50.1	51.0	51.3	51.6	52.3	53.2	54.1	54.7	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.4	60.0	60.6	61.3
Erindale TS T1/T2	**S**	**181.3**	208.3	210.2	211.9	212.6	210.9	208.7	208.2	207.4	206.5	206.3	206.1	205.8	205.6	205.4	205.2	205.0	204.8	204.5	204.3	204.1	203.9
Erindale TS T3/T4	**S**	**193.0**	150.6	150.9	151.0	150.8	149.4	148.0	148.0	147.8	147.5	147.1	146.7	146.4	146.0	145.6	145.2	144.8	144.5	144.1	143.7	143.4	143.0
Erindale TS T5/T6	**S**	**195.1**	171.9	172.2	172.4	172.2	170.6	169.0	169.0	168.8	168.4	168.0	167.5	167.1	166.7	166.3	165.8	165.4	165.0	164.6	164.1	163.7	163.3
Glenorchy MTS #1 T1/T2	**S**	**153.0**	50.1	57.5	68.0	80.7	107.4	133.5	152.4	158.9	91.0	94.9	98.9	103.1	107.6	112.2	117.0	122.0	127.2	132.6	138.3	144.2	150.4
Lorne Park TS T1/T2	**S**	**144.6**	119.4	118.4	120.4	122.5	123.3	123.9	125.6	127.7	130.0	131.4	132.8	134.2	135.7	137.1	138.6	140.1	141.6	143.1	144.6	146.2	147.8
Oakville TS #2 T5/T6	**S**	**185.2**	157.8	157.0	157.7	158.2	157.2	156.1	156.5	156.8	157.2	157.1	157.1	157.0	156.9	156.8	156.8	156.7	156.6	156.5	156.5	156.4	156.3
Palermo TS T3/T4	**S**	**109.5**	82.6	84.0	87.1	90.4	89.2	88.1	87.8	87.3	86.8	87.3	87.9	88.5	89.0	89.6	90.2	90.7	91.3	91.9	92.5	93.1	93.7
Tomken TS T1/T2	**S**	**173.3**	138.8	140.6	142.0	142.4	141.1	139.7	139.4	138.9	138.3	138.2	138.2	138.1	138.1	138.0	138.0	137.9	137.8	137.8	137.7	137.7	137.6
Tomken TS T3/T4	**S**	**192.8**	149.7	151.7	153.2	153.6	152.3	150.7	150.5	149.9	149.3	149.3	149.2	149.2	149.1	149.1	149.0	149.0	148.9	148.9	148.8	148.8	148.8
Trafalgar TS T1/T2	**S**	**124.0**	85.1	84.7	84.5	83.9	82.8	81.6	81.2	80.7	80.2	79.6	79.0	78.4	77.9	77.3	76.7	76.1	75.6	75.0	74.5	73.9	73.4
Tremaine TS T1/T2	**S**	**189.5**	72.9	79.7	86.8	92.6	91.8	91.1	91.1	90.9	90.7	93.3	96.0	98.7	101.5	104.4	107.4	110.4	113.6	116.8	120.1	123.6	127.1

Notes:

- Northern (N) Sub-Region's stations load forecast is based on the IRRP [1] "Expected Growth" Scenario.
- Southern (S) Sub-Region's stations load forecast is based on the NA [2] non-coincident stations load forecast.
- Halton Hills Hydro MTS and Halton TS #2 are assumed to be in-service in 2018 and 2020, respectively. Some load from Glenorchy MTS will be transferred to the new Halton TS #2 in 2023, as shown by the corresponding increase and decrease at those stations.
- Load forecast were updated for Palermo TS, Tremaine TS, and Glenorchy MTS based on new information provided by Milton Hydro and Burlington Hydro.

Appendix E. List of Acronyms

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

Kitchener-Waterloo-Cambridge-Guelph

REGIONAL INFRASTRUCTURE PLAN

December 15, 2015

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Cambridge and North Dumfries Hydro Inc.
Centre Wellington Hydro
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Distribution
Independent Electricity System Operator
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

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DISCLAIMER

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

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

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EXECUTIVE SUMMARY

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

The participants of the RIP Working Group included members from the following organizations:

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro One
- Hydro One Distribution
- Hydro One Transmission
- Independent Electricity System Operator
- Kitchener Wilmot Hydro Inc.
- Milton Hydro
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

This RIP provides a consolidated summary of needs and recommended plans for the KWCG Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified at this time.

This RIP is the final phase of the regional planning process and it follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015.

The major infrastructure investments planned for the KWCG Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Guelph Area Transmission Reinforcement	May 2016	$95 M
2	Arlen MTS: Install Series reactors	May 2016	$0.95 M
3	M20D/M21D – Install 230 kV In-line Switches	May 2017	$6 M
4	Waterloo North Hydro: MTS #4	2024	TBD

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle may be started earlier to address the need.

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Hydro One, Kitchener-Wilmot Hydro Inc. ("Kitchener-Wilmot Hydro"), Waterloo North Hydro Inc. ("WNH"), Cambridge & North Dumfries Hydro Inc. ("CND"), Guelph Hydro Electric Systems Inc. ("Guelph Hydro"), Hydro One Distribution and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

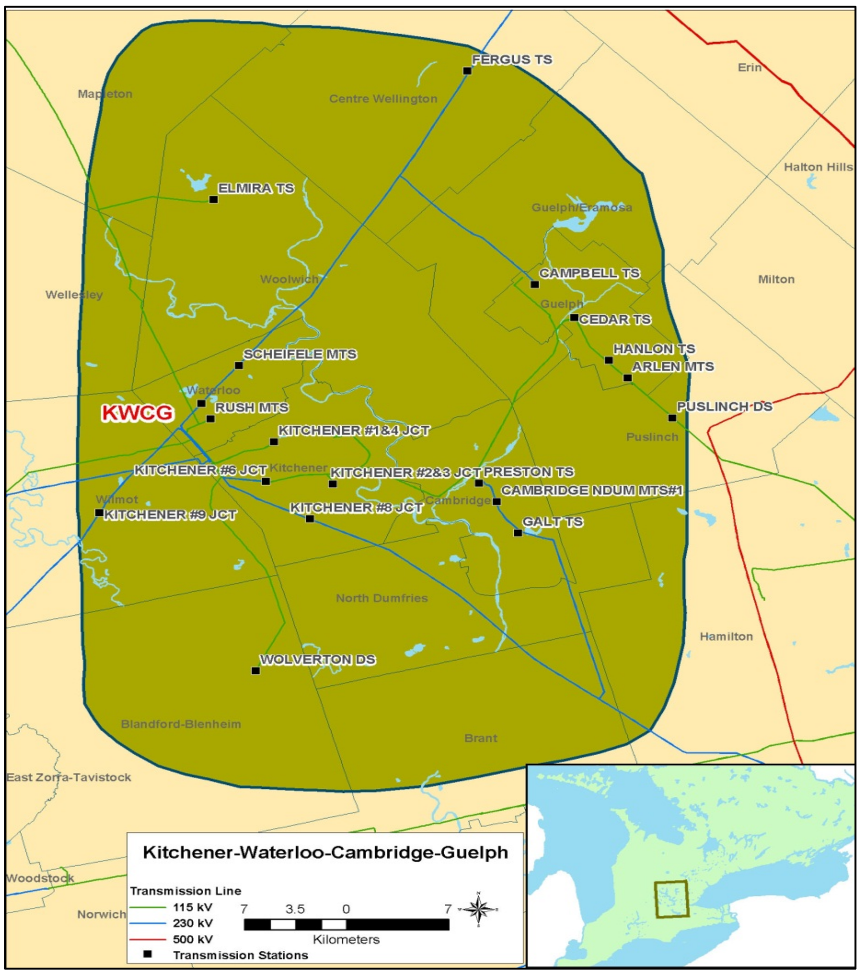

Figure 1-1 KWCG Region

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2015 coincident regional load was about 1240 MW. The boundaries of the Region are shown in Figure 1-1 above.

1.1 Scope and Objectives

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

- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To assess and develop a wires plan to address these needs
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

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

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated RIP phase information
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as the follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusions and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code ("TSC") and the Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation ("DG")) options at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best

[1] Also referred to a Needs Screening

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

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeliness provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

Note that as the KWCG Region was identified as a “transitional” region at the onset of the OEB defined Regional Planning process in 2013, the Needs Assessment and Scoping Assessment phases were deemed complete and the region was placed into the IRRP phase of the process.

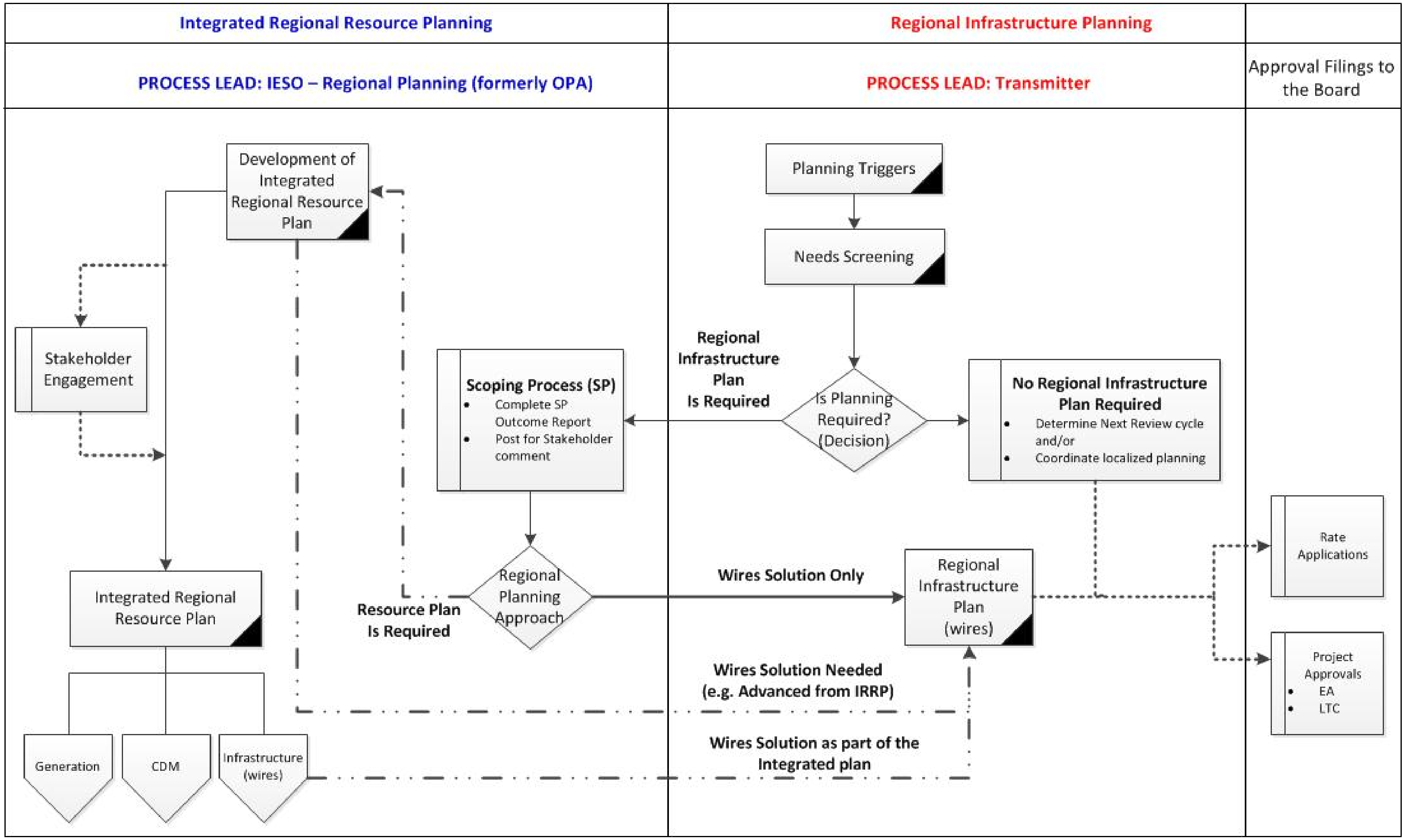

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

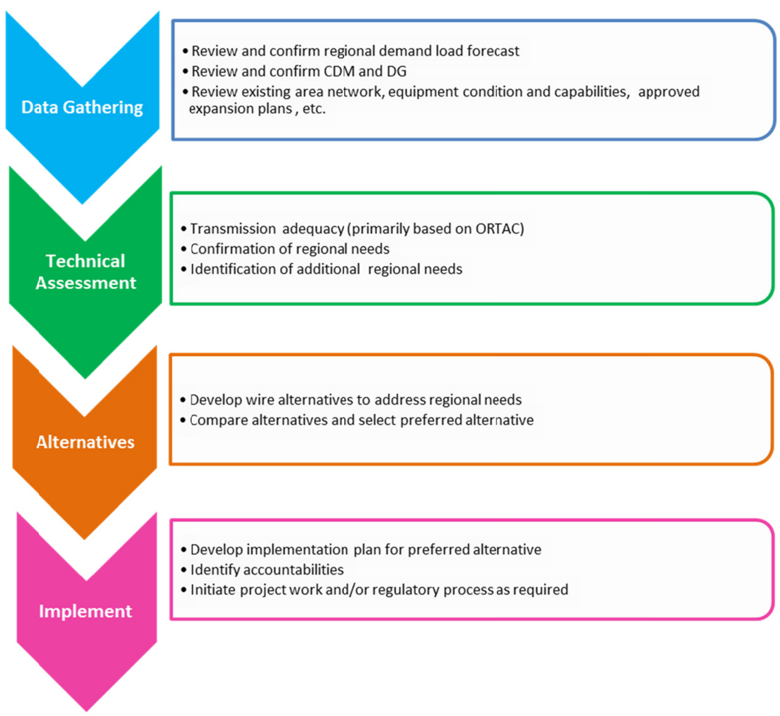

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by 24 step-down transformer stations. Figure 3-2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. Appendix A lists all step-down transformer stations in the KWCG Region, Appendix B lists all transmission circuits in the KWCG Region and Appendix C lists LDCs in the KWCG Region.

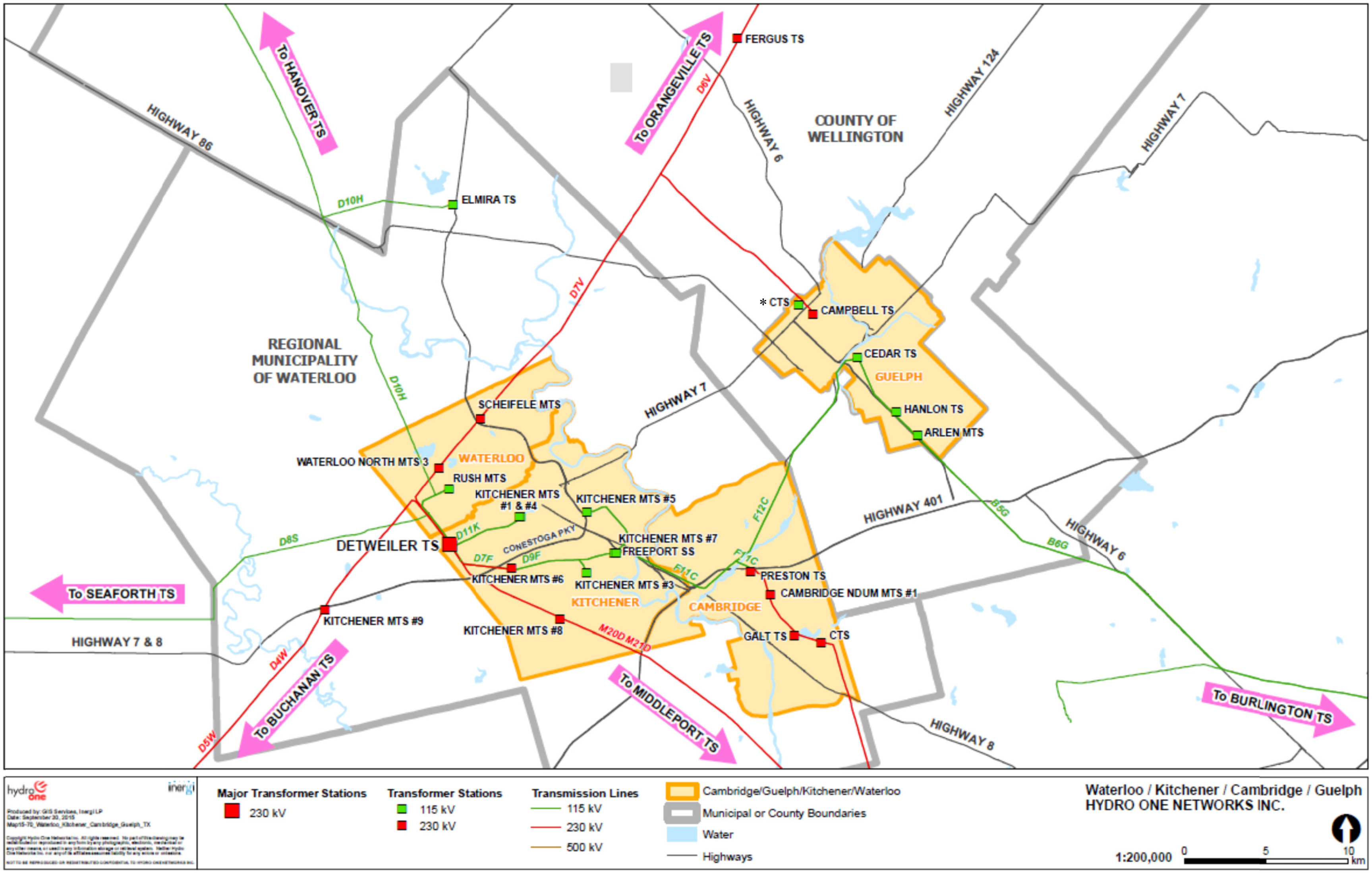

Figure 3-1 Geographical Area of the KWCG Region with Electrical Layout

*CTS relocated to the distribution system as part of the GATR project

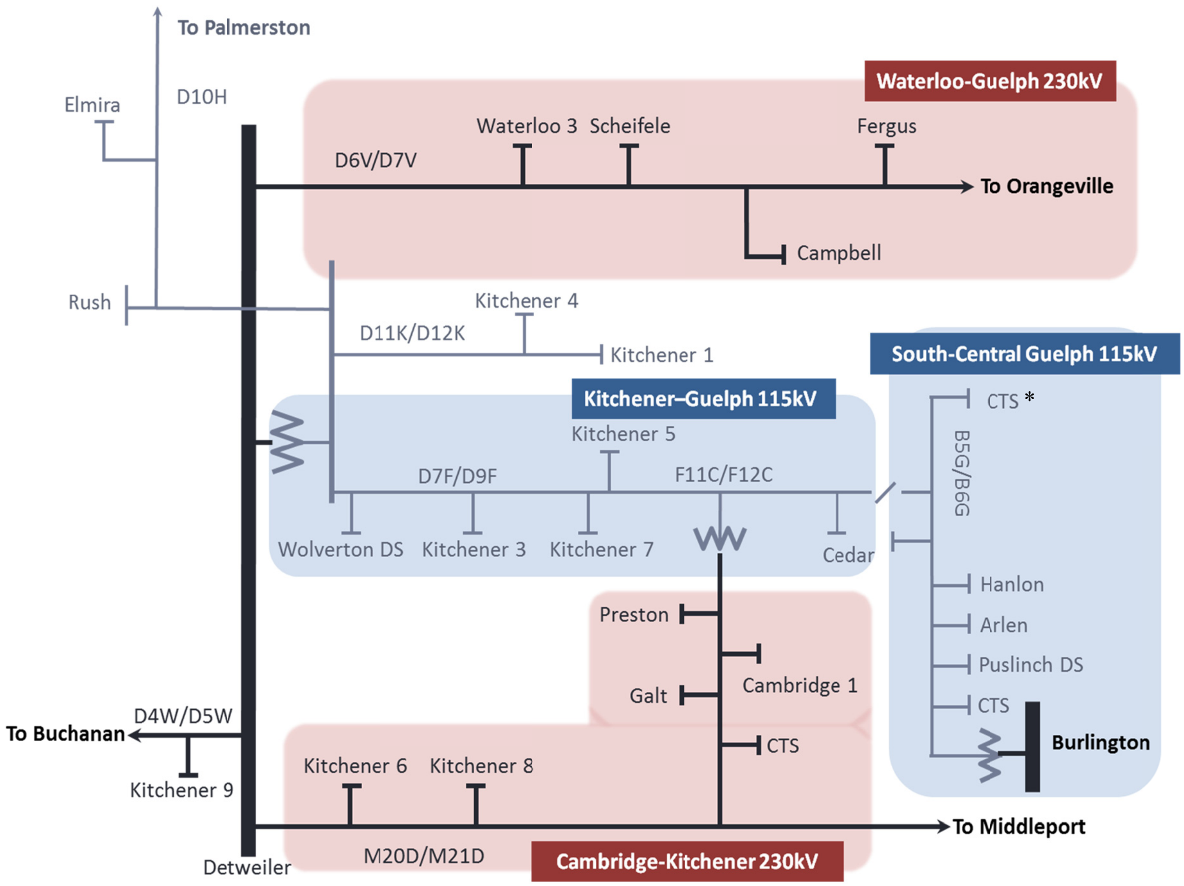

Figure 3-2 KWCG Single Line Diagram

*CTS relocated to the distribution system as part of the GATR project

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE KWCG REGION.

These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For transmission voltage level transformation capacity needs:

- 250 MVA 230/115 kV autotransformer T4 at Burlington TS replaced in 2006
- 250 MVA 230/115 kV autotransformer T6 at Burlington TS replaced in 2009

For distribution voltage level transformation capacity needs:

- Kitchener MTS#9 connected to replace the Detweiler TS DESN in 2010
- Arlen MTS connected in 2011

For reactive and voltage support needs:

- a 13.8 kV shunt capacitor bank installed at Cedar TS in 2006
- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008
- a 230 kV shunt capacitor bank installed at Burlington TS in 2010
- a 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For transmission circuit capacity needs:

- M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For transmission load security needs:

- Freeport SS installed to sectionalize circuits D7G/D9G (Detweiler TS by Cedar TS) in 2008

For transmission load restoration needs:

- 250 MVA 230/115 kV autotransformer T2 installed at Preston TS in 2007

The following projects are underway:

- Guelph Area Transmission Reinforcement (GATR) project that entails the extension the 230kV circuits D6V/D7V to Cedar TS; the installation of two new 250MVA, 230/115kV autotransformers at Cedar TS; and the installation of two 230 kV in-line switches onto circuits D6V/D7V at Guelph North Junction. This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system. This project is identified in the IESO KWCG IRRP, reference [1].

- The installation of a 13.8 kV series reactor to mitigate short circuit levels at Arlen MTS. This project was identified in the RIP phase.

- The installation two new 230kV in-line switches onto circuits M20D/M21D near Galt Junction to improve restoration capability in the Cambridge-Kitchener 230 kV sub-system. This project is identified in Hydro One's KWCG Adequacy of Transmission Facilities & Transmission Plan 2016-2025 report, reference [2]/Appendix F as well as reference [1].

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the KWCG Region is forecast to increase at an average rate of approximately 1.7% annually between 2015 and 2025. The growth rate varies across the Region with most of the growth concentrated in the cities of Waterloo and Guelph, each at an average rate of 2.5% over the next ten years.

Figure 5-1 shows the KWCG Region's planning load forecast (summer net, regional-coincident extreme weather peak). The regional-coincident (at the same time) forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. By 2025 the forecasted coincident regional peak load is approximately 1765 MW.

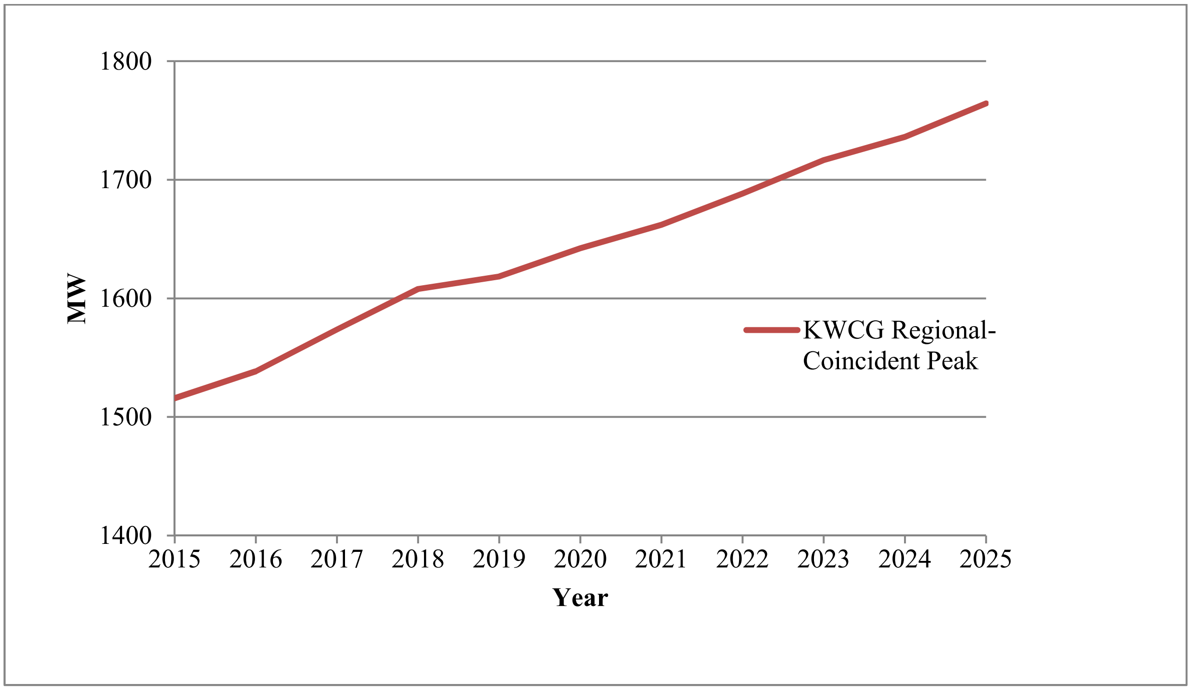

Figure 5-1 KWCG Region's Planning Forecast

The KWCG 2015 RIP planning load forecast is provided in Appendix D and is based upon the KWCG IRRP planning load forecast prepared by the IESO and was reaffirmed by the Working Group upon initiation of the RIP phase. In the IRRP phase, the LDC's provided the IESO with a 10 year gross, normal weather, regional-coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective CDM capacity, applying an extreme weather factor and then subtracting the effective DG capacity. Further details regarding the CDM and connected DG are provided in reference [1]. The RIP forecast is identical to the IRRP forecast except as otherwise noted in Appendix D.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.
6) Adequacy assessment is done as per the Ontario Resource and Transmission Adequacy Criteria ("ORTAC").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

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

Within the current regional planning cycle two regional assessments have been conducted for the KWCG Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's KWCG Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Adequacy of Transmission Facilities and Transmission Plan 2016-2025 – dated April 1, 2015 with revision 1 – dated October 30, 2015[2] (please see Appendix F)

The IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Guelph Area Transmission Reinforcement (GATR) project was initiated to provide adequate load supply capability to the KWCG area while the IRRP study was still underway. A detailed description and status of the GATR project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the KWCG Region assuming the GATR project is in-service. Sections 6.1-6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Medium Term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the IRRP [1] and the Adequacy Report [2]			
Transmission Circuit Capacity	7.1.1	South-Central Guelph 115 kV sub-system-Capacity of 115kV circuits B5G/B6G	Immediate
	7.1.2	Kitchener–Guelph 115 kV sub-system – Capacity of 115kV circuits D7F/D9F and F11C/F12C	Immediate
Load Restoration	7.1.3	Waterloo-Guelph 230 kV sub-system	Immediate
	7.2.1	Cambridge-Kitchener 230 kV sub-system	Immediate
Step-down Transformation Capacity	7.3.1	Waterloo North Hydro Inc.	2018
Additional Needs identified in RIP Phase			
Station Short Circuit Capability	7.4.1	Arlen MTS: Short Circuit capability	2016

6.1 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Detweiler TS to Orangeville TS 230 kV transmission circuits D6V/D7V – supplies Fergus TS, Campbell TS, Waterloo North MTS#3 and Scheifele MTS
2) Detweiler TS to Middleport TS 230 kV transmission circuits M20D/M21D – supplies Kitchener MTS #6, Kitchener MTS # 8, Cambridge MTS #1, Galt TS, Preston TS and Customer #1 CTS
3) Detweiler TS to Buchanan TS 230 kV transmission circuits D4W/D5W – supplies Kitchener MTS#9.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period. Refer to section 3.4.2 of Appendix F for the detailed analysis.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the KWCG Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

1) Two 500/230 kV autotransformers at Middleport TS
2) Four 230/115 kV autotransformers at Burlington TS
3) Three 230/115 kV autotransformers at Detweiler TS
4) Two 230/115 kV autotransformers at Cedar TS
5) One 230/115 kV autotransformer at Preston TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period. Refer to section 3.4.1 of Appendix F for the detailed analysis.

6.3 Supply Capacity of the 115 kV Network

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F – supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
2) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C – supplies Kitchener MTS#5 and Cedar T1/T2 transformers
3) Burlington TS to Cedar TS 115 kV transmission circuits B5G/B6G – supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
4) Detweiler TS 115 kV radial transmission circuit D11K/D12K – supplies Kitchener MTS#1 and Kitchener MTS#4
5) Detweiler TS to Seaforth TS/Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points – supplies Rush MTS and Elmira TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the supply capacity of the 115 kV network is adequate over the study period. Refer to section 3.4.3 of Appendix F for the detailed analysis.

6.4 Step-down Transformer Stations

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected industrial customer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

As part of the IRRP, step-down transformation station capacity was reviewed and resulted in the IRRP forecast which was reaffirmed by the Working Group for use in the RIP phase. According to the load forecast, Waterloo North Hydro anticipates requiring additional step-down transformation capacity in 2018.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Impact Assessment for the GATR project

Based on the Customer Impact Assessment [3] for the GATR project, Guelph Hydro identified the need to mitigate short circuit levels at Arlen MTS in order to ensure the short circuit levels remain within the TSC limits and equipment ratings. The project need date is May 2016 so as to correlate with the completion of the GATR project.

6.5.2 System Impact Assessment for the GATR Project

A System Impact Assessment ("SIA") [4] was performed for Hydro One's application to the IESO for the Guelph Area Transmission Reinforcement (GATR) project.

Several findings emanated from the SIA report due to conservative assumptions made for the Bulk Power System. The Working Group has reviewed these findings and recommends that the assumptions be looked at in greater detail within a Bulk Power System study. If the Bulk Power System study results in regional needs then an early trigger of the next Regional Planning cycle may occur.

6.5.3 Load Restoration to the Cambridge area

The IRRP recommended Hydro One to continue to explore options with Cambridge and North Dumfries Hydro ("CND") to further improve the load restoration capability to the Cambridge area. During the RIP phase Hydro One presented to CND a detailed explanation of its capability to restore power to transformer stations that service the Cambridge area. Based on this discussion, CND and Hydro One have agreed that, at this time, no additional infrastructure is required and the restoration capability afforded by the GATR project and the 230 kV in-line switches at Galt Junction is acceptable for the study period.

6.6 Long-Term Regional Needs

The IRRP examined high-growth and low-growth scenarios to identify long-term needs. Under the high-growth scenario, there is sufficient transmission capacity afforded by the GATR project to meet demand in the long-term; however the need for additional step-down transformation capacity may arise. LDC's to closely monitor their load to determine the timing of potential step-down transformation needs. Under the low-growth scenario, no needs were identified in the long-term.

Consistent with the IRRP, the Working Group did not identify any additional long-term needs during the RIP phase. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions..

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE KWCG REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP AS WELL AS THE NEEDS IDENTIFIED DURING THE RIP PHASE.

7.1 Transmission Circuit Capacity and Load Restoration

7.1.1 South-Central Guelph 115 kV Sub-system

The South-Central Guelph area is supplied by the 115 kV double circuit line B5G/B6G. As per section 6.2.1 of the IRRP, historical peak demand on the B5G/B6G line has already exceeded the 100 MW line Load Meeting Capability ("LMC").

7.1.2 Kitchener-Guelph 115 kV Sub-system

The Kitchener-Guelph area is supplied by two 115 kV double-circuit lines D7F/D9F and F11C/F12C supported by 230/115 kV autotransformers at Detweiler TS and Preston TS. As per section 6.2.1 of the IRRP, the planning forecast peak demand in the Kitchener-Guelph 115 kV sub-system will exceeded the 260 MW line LMC by summer 2014.

7.1.3 Waterloo-Guelph 230 kV Sub-system

As per section 6.2.2 of the IRRP, the transmission infrastructure supplying load in the Waterloo-Guelph 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, D6V and D7V.

7.1.4 Recommended Plan and Current Status

To address the transmission circuit capacity needs for the South-Central Guelph 115 kV sub-system and the Kitchener-Guelph 115 kV sub-system, the IRRP Working Group recommended reinforcement of the 115 kV transmission system by introducing a new 230 kV – 115 kV injection point. The new injection point is to be located at Cedar TS using two new 230 kV/115 kV autotransformers in conjunction with a 5 km extension of the existing 230 kV double-circuit transmission line, D6V/D7V from Campbell TS to Cedar TS. This reinforcement is covered under the GATR project.

To address the load restoration need of the Waterloo-Guelph 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches near Guelph North Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is also covered under the GATR project.

Current Status of the GATR Project

Hydro One initiated construction on the GATR project in fall 2013 following the OEB approval in September 2013. The project has three components:

- Campbell TS x Cedar TS: Extend the 230 kV D6V/D7V tap from Campbell TS to Cedar TS. This requires replacing approximately a 5 km section of the existing 115 kV double circuit transmission section between CGE Junction and Campbell TS with a new 230 kV double circuit transmission line,
- Cedar TS: Install two new 230/115 kV autotransformers and associated 115 kV switching facilities at Cedar TS. Connect 115 kV switching facilities to the existing B5G/B6G line and the F11C/F12C at Cedar TS.
- Guelph North Junction: Install two in-line 230 kV switches at Guelph North Jct.

This investment will provide for sufficient 230/115 kV autotransformation capacity beyond the study period. The current in-service date of the project is May 2016.

The cost of this project is approximately $95 million. The project is a transmission pool investment as the autotransformers provide supply to all customers in the Region.

7.2 Load Restoration

7.2.1 Cambridge-Kitchener 230 kV Sub-system

As per section 6.2.2 of the IRRP and the section 3.4.8 of the Adequacy of Transmission Facilities report, transmission infrastructure supplying load in the Cambridge-Kitchener 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, M20D and M21D.

7.2.2 Recommended Plan and Current Status

To address the load restoration need of the Cambridge-Kitchener 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches on the M20D/M21D line near Galt Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is covered under the M20D/M21D Install 230 kV In-line Switches project.

Current Status of the 230 kV In-Line Switches near Galt Junction

Hydro One has established a project to install the two 230 kV in-line switches onto the M20D/M21D double circuit line. One set of switches to be installed onto each circuit. One set of switches to be installed north of the Junction while the other to be installed south of Galt Junction. The switches will enable

Hydro One to quickly isolate a problem on either side of the junction and initiate the restoration of load to the Cambridge-Kitchener 230 kV sub-system.

The project is currently in the detailed design and estimation phase which also includes real estate negotiations. The cost of this project is approximately $6 million and it will be a transmission pool investment. The planned in-service date is May 2017.

7.3 Step-down Transformation Capacity

7.3.1 Waterloo North Hydro

The RIP/IRRP planning load forecast indicates that additional step-down transformation capacity is required by 2018, specifically Waterloo North Hydro's MTS #4.

7.3.2 Recommended Plan and Current Status

To address step-down transformation capacity needs of Waterloo North Hydro, Waterloo North Hydro will, wherever possible, manage load growth by maximizing the utilization of existing stations by increasing distribution load transfer capability between those stations and will continue to explore opportunities for CDM and DG. In addition Waterloo North Hydro will also explore, with other LDCs, opportunities to coordinate possible joint use and development of step-down transformer stations in the Region over the long term. With this in mind, additional step-down transformation capacity is not anticipated prior to 2024. This need will be reviewed in the next cycle of regional planning.

7.4 Station Short Circuit Capability

7.4.1 Arlen MTS

Arlen MTS is a 115/13.8 kV step-down transformer station owned by Guelph Hydro. As a result of the new 230/115 kV injection point afforded by the GATR project, the short circuit levels at Arlen MTS's 13.8 kV bus will exceed the TSC limit and equipment capability.

7.4.2 Recommended Plan and Current Status

To address the station short circuit capability need at Arlen MTS, Guelph Hydro will install series reactors to bring station short circuit levels within TSC limits and within equipment ratings.

Current Status of Short Circuit Mitigation

Guelph Hydro has initiated a project to install series reactors to bring station short circuit levels within TSC limits and equipment ratings. The cost of this project is $0.95 million and the expected completion date is May 2016 so as to correlate with the completion of the GATR project.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE KWCG REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

Six near and mid-term needs were identified for the KWCG Region. They are:

I. Transmission capacity in the South-Central Guelph 115 kV sub-system
II. Transmission capacity in the Kitchener-Guelph 115 kV sub-system
III. Load restoration capability in the Waterloo-Guelph 230 kV sub-system
IV. Load restoration capability in the Cambridge-Kitchener 230 kV sub-system
V. Step-down transformation capacity for Waterloo North Hydro
VI. Station Short Circuit Capacity at Arlen MTS

This RIP report addresses all six of these needs. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near and mid-term needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
1	Guelph Area Transmission Reinforcement	Construction in the final stages	Hydro One	May 2016	$95M	I, II, III
2	Mitigate Short Circuit Levels at Arlen MTS	Construction underway	Guelph Hydro	May 2016	$0.95M	VI
3	M20D/M21D – Install 230 kV In-line Switches	Transmitter to carry out this work	Hydro One	May 2017	$6M	IV
4	Waterloo North Hydro: MTS #4	LDC to monitor growth	Waterloo North Hydro	2024	TBD	V

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator, Kitchener-Waterloo-Cambridge-Guelph Region Integrated Region Resource Plan, 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/KWCG/2015-KWCG-IRRP-Report.pdf

[2] Hydro One Networks Inc., Kitchener-Waterloo-Cambridge-Guelph Area – Adequacy of Transmission Facilities and Transmission Plan 2016-2025, 1 April 2015, revised 30 October 2015.

[3] Hydro One Networks Inc., Customer Impact Assessment Guelph Area Transmission Refurbishment Project, 28 May 2013,

[4] Independent Electricity System Operator, System Impact Assessment, CAA ID: 2012-478, Project: Guelph Area Transmission Refurbishment, 17 May 2013.
http://www.ieso.ca/Documents/caa/CAA_2012-478_GATR_Final_Report.pdf

Appendix A. Step-Down Transformer Stations in the KWCG Region

Station	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Cambridge MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5G/B6G
Arlen MTS	115 kV	B5G/B6G
Hanlon TS	115 kV	B5G/B6G
Cedar TS (T8/T7)	115 kV	B5G/B6G
Customer #2 CTS	115 kV	B5G
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5G/B6G	115 kV
Detweiler TS – Kitchener MTS #4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Guelph Hydro Electric System - Rockwood Division	Fergus TS	Dx
Guelph Hydro Electric Systems Inc.	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Regional Load Forecast (2015-2025)

Table D-1 RIP Planning Demand Forecast (MW)

Station	LDC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS (1)	Cambridge & North Dumfries Hydro	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Kitchener MTS #6	Kitchener-Wilmot Hydro	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Wolverton DS	Hydro One Distribution	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Cedar TS T1/T2	Guelph Hydro	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cambridge MTS # 2 (2)	Cambridge & North Dumfries Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #5	Kitchener-Wilmot Hydro	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Cedar TS T7/T8	Guelph Hydro	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Puslinch DS	Hydro One Distribution	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Arlen MTS	Guelph Hydro	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo North MTS #3	Waterloo North Hydro	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
MTS #4(2)	Waterloo North Hydro	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Fergus TS	Hydro One Distribution	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Kitchener MTS #1	Kitchener-Wilmot Hydro	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Kitchener MTS #4	Kitchener-Wilmot Hydro	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Elmira TS (3)	Waterloo North Hydro/ Hydro One Distribution	38.0	32.6	33.5	33.3	34.8	35.4	36.0	36.8	38.4	39.0	40.6
Rush MTS	Waterloo North Hydro	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS (4)	Customer Station	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Station (Assumed Values)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Table D1 -is based upon KWCG 2015 IRRP Planning Load Forecast except as noted.

(1) Cambridge and North Dumfries Hydro ("CND") has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expected to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

(2) Both CND and Waterloo North Hydro ("WNH") are monitoring the load closely to determine the timing of potential transformation needs. For planning purposes, WNH has moved back the in service date of MTS #4 from 2018 to 2024. WNH is closely monitoring the need for additional transformation capacity to determine if the load growth indicated at MTS #4 in the forecast can be managed through a combination of improving transformer station interties, CDM and DG in the Waterloo Region. Where possible, these LDCs are exploring opportunities to coordinate possible joint use and development of step-down transformer station facilities in the KWCG Region over the long term.

(3) Updated to include Hydro One Distribution load

(4) Based on information provided by the transmission-connected customer

Appendix E. List of Acronyms

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

Appendix F. KWCG Adequacy of Transmission Facilities and Transmission Plan 2016-2025

Revision 1

KITCHENER/WATERLOO/CAMBRIDGE/GUELPH AREA

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2016 – 2025

October 30, 2015

Prepared by Hydro One Networks Inc. in Consultation with the KWCG Working Group

Foreword

This report is the result of a joint study by KWCG Working Group. It has been prepared by Hydro One Networks in consultation with the Working Group.

The working group members were:

Entity	Member
Kitchener-Wilmot Hydro	Shaun Wang L. Frank G. Cameron
Waterloo North Hydro Inc.	Herbert Haller David Wilkinson Dorothy Moryc
Cambridge & North Dumfries Hydro	Ron Sinclair Shawn Jackson
Guelph Hydro Electric System Inc.	Michael Wittemund K. Marouf Eric Veneman
Hydro One Distribution	Charlie Lee
Ontario Power Authority	Bob Chow Bernice Chan
Independent Electricity Operator	Peter Drury
Hydro One Networks Inc.	Alessia Dawes Farooq Qureshy Emeka Okongwu Qasim Raza

The preferred plan has been selected based on technical and economic considerations. The issue of cost allocation between utilities was not addressed.

Prepared by: Qasim Raza – Transmission Planning Officer

Reviewed by: Alessia Dawes – Senior Transmission Planning Engineer

Approved by: Farooq Qureshy – Manager, Transmission System Development, Central & East

October 30, 2015

Revision History

Revision	Date	Author	Description of change
1	October 30, 2015	Qasim Raza	Refreshed based on 2015 IRRP/RIP load forecast (April/August2015)
0	April 1, 2015	Alessia Dawes	Original- based on May 2013 forecast

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EXECUTIVE SUMMARY

In 2010 an integrated regional planning study was initiated to assess the electricity supply and reliability over a twenty year period for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) areas and continues to be conducted by a Working Group led by the Ontario Power Authority (OPA) and includes staff from the Independent Electricity System Operator (IESO), Hydro One Networks Inc., Kitchener-Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro, Guelph Hydro Electric Systems Inc. and Hydro One Distribution.

The early results of the integrated regional planning study identified the need to reinforce supply capacity for the South-Central Guelph and the City of Cambridge over the near and medium term. It also identified the need to minimize the impact of double circuit interruptions in the area[1]. As a result, the Working Group recommended two transmission projects in conjunction with conservation and distributed generation:

1. The Guelph Area Transmission Reinforcement (GATR) project – comprising a new 230/115kV autotransformer station at Guelph Cedar TS, upgrading the circuit section between Campbell TS and CGE Junction to 230 kV and in-line switching on the Orangeville TS x Detweiler TS 230kV circuits D6V/D7V – to reinforce supply to South Central Guelph,
2. The Preston TS Autotransformer Project – comprising the installation of a second 230/115kV autotransformer at Preston TS - to reinforce supply to the City of Cambridge.

Work on the GATR project was started in 2014 following approval from the Ontario Energy Board and the Ministry of Environment. The project's planned in-service date is June 2016.

For the Preston project, the OPA issued Hydro One a hand off letter to develop a "Wires" solution to improve the supply to the Cambridge area and to facilitate the connection of a future Cambridge and North Dumfries Hydro transformer station by 2018.

This report presents the results of Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016. The main conclusions of the report are as follows:

- The supply capability to the KWCG 115kV area has been significantly increased to meet all 2025 forecast loads by the addition of the GATR project. The need for the Preston autotransformer can be deferred to beyond 2025.
- There is inadequate load restoration capability for load connected to Middleport TS x Detweiler TS 230kV double circuit line M20D and M21D

This report recommends that the most cost effective plan to improve load restoration capability for load connected to circuits M20/21D is to install 230 kV in-line switches onto circuits M20/21D.

[1] OPA Submission to the OEB for the GATR Project – Document EB-2013-0053 dated March 8, 2013 entitled, "Kitchener-Waterloo-Cambridge-Guelph Area

1.0 INTRODUCTION

This transmission adequacy assessment focused on the electrical supply to the municipalities of Kitchener, Waterloo, Cambridge and Guelph and their surrounding areas of Ontario, collectively referred to as the KWCG area in this report. Its primary focus was to confirm the near and mid-term transmission needs for the area and to provide a 10-year transmission plan in order satisfy those Needs.

Geographically, the KWCG area consists of 4 municipalities – Kitchener, Waterloo, Cambridge, Guelph and portions of two counties - Perth and Wellington. Hydro One Networks Inc. is the sole high voltage transmitter in the KWCG area; however the low voltage distribution of electricity in the KWCG area is carried out by Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric System Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc., and Waterloo North Hydro. A geographic map of the area is shown in Appendix A, Map 1 while an electrical map of the area is shown in Appendix A, Map 2.

The KWCG area is a major regional load centre in Ontario. The area has a well-established history in manufacturing and technology. The area peak load is approximately 1400 MW.

This report presents the results of the Hydro One led “Wires” study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016.

2.0 EXISTING TRANSMISSION INFRASTRUCTURE

2.1 TRANSMISSION IN KWCG

Electrical Supply in this area is provided through 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as show in Appendix A, Map 2.

The main sources of electricity into the KWCG Region are Middleport TS, Detweiler TS, Orangeville TS, Cedar TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. The KWCG Region transmission system is connected as follows:

- Two 230 kV circuits (D6V/D7V) that run North-East from Detweiler TS to Orangeville TS that supply five load serving stations;
- Two 230 kV circuits (M20/21D) that run South-East from Detweiler TS to Middleport TS that supply five load serving stations and one transmission-connected customer;
- Two 230 kV circuits (D4W/D5W) that run South-West from Detweiler TS to Buchanan TS (in the "London area") that supply one load serving station;
- Four 115 kV circuits (D7F/D9F, F11C/F12C) that run East-West: D7/9F from Detweiler TS to Freeport SS that supply three load serving stations and F11/12C from Freeport SS to Cedar TS that supply one load serving station;
- Two 115 kV circuits (B5G/B6G) that run North-West from Burlington TS to Cedar TS that supply three load serving stations and one transmission-connect customer;
- Two 115 kV radial circuits (D11K/D12K) emanating East from Detweiler TS that supply two load serving stations; and,
- Two 115 kV circuit (D8S and D10H) emanating North from Detweiler TS that supply two load serving stations in the KWCG area.

Voltage support is provided in the area by:

- Four high voltage shunt capacitor banks and one SVC at Detweiler TS
- Four high voltage shunt capacitor banks at Middleport TS
- Three high voltage shunt capacitor banks at Burlington TS
- One high voltage shunt capacitor bank at Orangeville TS
- 43.2 MVar low voltage station shunt capacitor at Galt TS
- 21.6 MVar low voltage station shunt capacitors at Campbell TS
- 59.81 MVar low voltage station shunt capacitors at Cedar TS
- 9.92 MVar low voltage station shunt capacitors at Elmira TS
- Low voltage feeder shunt capacitors were lumped at: C&ND MTS#1, Waterloo North Hydro MTS #3, Scheifele MTS

All stations in the KWCG Region were considered in the analysis to determine the adequacy of the existing transmission system. Transformation capacity at individual load serving stations was previously analyzed by the OPA as part of the Integrated Regional Resource Plan (IRRP). The result of that analysis was a load forecast that included proposed new stations, as shown in Appendix C. Therefore, transformation capacity at individual load serving stations was not considered in this study.

2.2 Transmission-Connected Generation

There are no existing large-scale transmission-connected generation plants in the KWCG area; however two contracted renewable transmission-connected wind farms were included in the study area and are listed in Appendix B.

3.0 Adequacy of Existing Transmission Infrastructure in KWCG area

3.1 Study Assumptions

Assumptions were made in order to assess the effects of contingencies to verify the adequacy of the transmission system. The assumptions used in the study were:

1. A 10 year load forecast: years 2016 to 2025; shown in Appendix C
2. Forecasted loads were provided by the LDC's in MW. The MVAR portion of the load was set to 40% of the MW load which is a reasonable assumption to achieve a power factor of 0.9 at the defined meter point of load serving transformer stations (TS, CTS, MTS)
3. A summer assessment was performed as the KWCG area is summer load peaking while the equipment is at its lowest rating during summer ambient conditions. This was deemed to be the most conservative approach;
4. Equipment continuous and Limited Time Ratings (LTR) were based on an ambient temperature of 35°C for summer and a wind speed of 4 km/hour;
5. The Guelph Area Transmission Reinforcement (GATR) project would be in-service in June 2016;
6. Circuits M20D and M21D are assigned their updated long-term emergency rating (LTE) based on a maximum temperature of 127°C;
7. Simulation of year 2025 load forecast was performed as it was the maximum loading of the area for the duration of the study period; year 2016 was simulated as necessary;
8. Waterloo North Hydro's Snider MTS #4 (MTS #4) will connect to 230 kV circuit D6/7V between Scheifele MTS and Guelph North Jct., projected in-service date 2024 (refer to Note 2 in Appendix C, Table C1)
9. The flows on Ontario's major internal transmission interfaces were assumed as follows:
    - FETT ~ 4500 MW
    - FS ~1250 MW
    - FABCW ~ 5800MW
    - NBLIP ~ 1650 MW (the slightly high NBLIP was offset by the lower FABCW)
    - QFW ~ 1550 MW

3.2 Study Criteria

The adequacy of the transmission system is assessed as per the IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0.

3.3 Load Forecast

The load forecast used in this assessment is the KWCG 2015 RIP forecast as shown in Appendix C. This summer forecast is an extreme weather, area coincident, net, peak load forecast.

The KWCG 2015 RIP forecast is based upon the KWCG 2015 IRRP forecast. The LDC's provided the IESO with a 20 year gross, normal weather, area coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective conservation and demand management (CDM) capacity, applying an extreme weather factor and then subtracting the effective Distribution Generation (DG) capacity.

3.4 Supply Capacity Needs

Single element contingencies were considered in assessing the adequacy and reliability of the local transmission system that serves the KWCG area. Figure 1 summarizes the local KWCG area Needs for the 10-year period under study. Appendices D, F and G detail the technical study and results.

At stations, within the KWCG area, classified as NPCC Bulk Power System (BPS) additional contingencies were considered to establish their impact to the local KWCG area. Appendix E details the technical study and results.

3.4.1 Auto-transformation Supply Capacity

There is no major generation station in the KWCG area. Hence, the majority of supply to the load is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV auto-transformers. The number and location of these auto-transformers are as follows:

- Two 500/230 kV autotransformers at Middleport TS
- Four 230/115 kV autotransformers at Burlington TS[2]
- Three 230/115 kV autotransformers at Detweiler TS
- Two 230/115 kV autotransformers at Cedar TS
- One 230/115 kV autotransformer at Preston TS

Single autotransformer contingencies were performed to assess the adequacy of the transmission system to supply bulk power into the KWCG area via the autotransformers for year 2025 loading.

The results indicate that there are no thermal overloads and no voltage violations for the loss of a single autotransformer.

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[2] The loading of the autotransformers at Burlington TS is mainly driven by the load connected in the Burlington to Nanticoke area. Only a small percentage of the autotransformer load is due to local Guelph load and as such, analysis of the Burlington TS autotransformers was undertaken in the 'Burlington to Nanticoke' Regional Infrastructure Plan.

3.4.2 SUPPLY CAPACITY OF THE 230 kV NETWORK

The KWCG area contains three pairs of double circuit 230 kV lines: M20D/M21D, D6V/D7V and D4W/D5W.

Single circuit contingencies were performed to assess the adequacy of the local 230 kV transmission system for year 2025 loading[3].

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 230 kV circuit.

3.4.3 SUPPLY CAPACITY OF THE 115 kV NETWORK

The KWCG area contains five pairs of double circuit 115 kV lines: D7F/D9F, F11C/F12C, B5G/B6G, D11K/D12K and D8S/D10H.

Single circuit contingencies were performed to assess the adequacy of the local 115 kV transmission system for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 115 kV circuit. Appendix H details supply capacity on circuit D8S and D10H as request by the LDC.

3.4.4 VOLTAGE PERFORMANCE

Single circuit contingencies as well as single element HV shunt capacitor bank contingencies were performed to determine the overall voltage performance of the KWCG area for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for these contingencies. Appendix H details voltage performance at Elmira TS and Rush MTS as request by the LDC.

3.4.5 LOAD SECURITY ANALYSIS

The most stringent load security criterion that applies to the KWCG area states that with any two elements out of service:

- Voltage must be within applicable emergency ratings and equipment loading must be within applicable short-term emergency ratings;
- Load transfers to meet the applicable long-term emergency ratings must be able to be made in the time afforded by short-time ratings;
- Planned load curtailment or load rejection in excess of 150 MW is not permissible (except for local generation outages) and;

[3] Note, if another element such as an autotransformer, circuit or capacitor bank shared the same "switching position" and/or zone of protection with the circuit under contingency, both were removed from service.

- Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection excluding voluntary demand management with any two transmission elements out of service.

There are three pairs of 230 kV double circuit lines and five pairs of 115 kV double circuit lines in the KWCG area. While one circuit of a double circuit line is out of service, the loss of the companion circuit in the pair would result in the loss of all load stations connected to the pair by configuration. Tables F1 and F2 in Appendix F illustrate the load lost due to configuration in both years 2016 and 2025.

There are five stations in the KWCG area that have autotransformers. Overlapping autotransformer contingencies were taken and Table F3 in Appendix F illustrates any load transfer requirements due to two overlapping autotransformer outages.

As seen in Appendix F, the load forecasted on all circuit pairs is less than 600 MW within the 10-year study period and the loss of two autotransformers within this local area does not result in equipment loading beyond their applicable emergency ratings; therefore there is no concern with Load Security in the KWCG area for the study period.

3.4.6 Load Restoration Capability Analysis

The load restoration criteria requires that the transmission system be planned such that following local area design criteria contingencies, the affected loads can be restored within the restoration times indicated below[4]:

- All load lost must be restored within 8 hours;
- Load lost in excess of 250 MW must be restored within 30 min; and
- Load lost between the amount of 150 MW and 250 MW must be restored within 4 hours.

Each pair of double circuit 230 kV and 115 kV lines were assessed to verify their load restoration capability. This assessment is detailed in Appendix G.

The results indicated the existing transmission system can adequately restore load to each circuit pair with the exception of M20/21D. Therefore, improvement to the restoration capability of load connected to circuits M20D and M21D is required.

3.4.7 Impact of Contingencies on the BPS to the KWCG Area

Northeast Power Coordinating Council (NPCC) Bulk Power System stations in the KWCG area are:

- Middleport TS 500 kV bus
- Middleport TS 230 kV bus
- Detweiler TS 230 kV bus

[4] As per ORTAC: "These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility."

All elements connected to BPS buses are considered BPS facilities. Elements refer to circuit breakers, transmission lines, generators, transformers and reactive devices (e.g. SVC or capacitor bank).

Appendix E: Technical Results-Bulk Power System Considerations provides a list of BPS contingencies and the results. A *limited* number of BPS contingencies were performed in order to establish the impact of contingencies on the BPS to the local KWCG area.

Three NPCC Directory 1 contingency events were utilized in this study:

1. Simultaneous loss of two adjacent transmission circuits on a multiple circuit tower
2. Loss of any element with delayed fault clearing (a.k.a. Breaker Failure)
3. Loss of a critical element, followed by system adjustment, then loss of a critical element.

These BPS contingency events were applied to BPS buses only. The results can be summarized as follows:

- As per Table E3 and E5 when two of the three auto-transformers at Detweiler TS are not available the remaining auto-transformer may become overloaded. Since the loading of the remaining auto-transformer is within its 15-minute Short-Term Emergency Rating (STE) operational control actions can be taken to reduce the loading to within acceptable limits. Control actions could entail isolation of the faulted element e.g. circuit breaker, bus or transformer, and placing back in-service a healthy auto-transformer (at Detweiler TS and/or Preston TS). Another control action could entail opening of 115kV breakers at Freeport SS to redirect flows through the Cedar TS autotransformers.

3.4.8 Summary of Needs

Figure 1 illustrates the Needs timeline for the KWCG region.

Figure 1: Transmission Needs in the KWCG Area

4.0 Options to Address the Need

Options were considered to address the insufficient load restoration capability for loads connected to circuits M20D and M21D. These options are shown in Table 1. Although there are several metrics that can be utilized to measure and compare options, the simple metric “initial capital cost/MW of load restored” was selected because it compares the unit costs of remedial measures. This was deemed sufficient in order to select the preferred option

Table 1: Options to Improve M20/21D Load Restoration

Option	**Options to Improve Restoration**	**Fault on the Main Line – Restorable Load** (Note 1)	**Fault on the Tap – Restorable Load** (Note 1)	**Initial Capital Cost** (Note 3)	**Initial Capital Cost/ MW Load Restored**
--	Existing (Benchmark)	100 MW (Preston TS only)	100 MW (Preston TS only)	0	$0/MW
1	230 kV in-line switches on M20/21D at **Preston Junction**	100 MW (C&ND load only-Note 2)	100 MW (C&ND load only-Note 2)	$6M	$60k/MW
2	230 kV in-line switches on M20/21D at **Galt Junction** (main line)	368 MW - 484 MW	234 MW (100 MW via existing Preston Auto)	$6M	$12k/MW to $26k/MW
3	One 230 kV cap bank at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	140 MW (Note 4) (C&ND load only-Note 2)	140 MW (Note 4) (C&ND load only-Note 2)	$11M	$79k/MW
4	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	200 MW (Note 4) (C&ND load only-Note 2)	200 MW (Note 4) (C&ND load only-Note 2)	$21M	$105k/MW
5	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction** plus two 230 kV cap banks at Preston TS	280 MW (Note 4) (C&ND load only-Note 2)	280 MW (Note 4) (C&ND load only-Note 2)	$31M	$111k/MW

NOTE 1 Restorable load values are approximate values only as the actual amount of restorable load will depend on the prevailing system conditions and Operating/Control Centre protocols and priorities

NOTE 2 "C&ND load only" means that only those customers connected to Galt TS, C&ND MTS#1 and Preston TS will benefit. Cambridge and North Dumfries Hydro customers are the sole customers of these three stations.

NOTE 3 All prices are based on historical data: taxes extra, overhead extra, no escalation considered, no assumptions are made to feasibility or constructability, no assumptions made as to space requirements, real estate and environmental cost extra

NOTE 4 Restoration of 230 kV load (Cambridge and North Dumfries load) via the Preston TS auto-transformer may require operational measures on the 115 kV system to secure the transmission system to handle a subsequent contingency e.g. open the low voltage bus-tie breakers/switches at 115kV connected stations

5.0 DISCUSSION OF PREFERRED OPTIONS

5.1 PREFERRED OPTION TO IMPROVE RESTORATION TO M20/21D LOAD

Currently, loads connected to circuits M20/21D do not meet the restoration criteria.

Of the five options, option #2: 230 kV in-line switches on M20/21D at/near Galt Junction is the preferred option to satisfy the Need as it will provide the capability to restore the most load supplied from M20/21D.

Not only does Option #2 allow for more load to be restored, it provides for better operational flexibility; and is the most economical solution. As option 2 substantially meets the need by significantly improving the existing restoration capability, it is therefore the preferred option.

6.0 DEVELOPMENT PLAN

The transmission infrastructure development plan for the KWCG area is as followings:

1) <u>Immediate Action: Install 230 kV In-Line Switches</u>

Install 230 kV Load Interrupter type in-line switches on circuits M20D and M21D on the main line near Galt Junction. Note that load interrupter type switches cannot be used to interrupt fault current.

7.0 CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

<u>Local Area Performance</u>

1. Improvement to the load restoration capability of transmission-connected customers on circuits M20D and M21D is required. The preferred option can be implemented by summer 2017.

<u>BPS Performance</u>

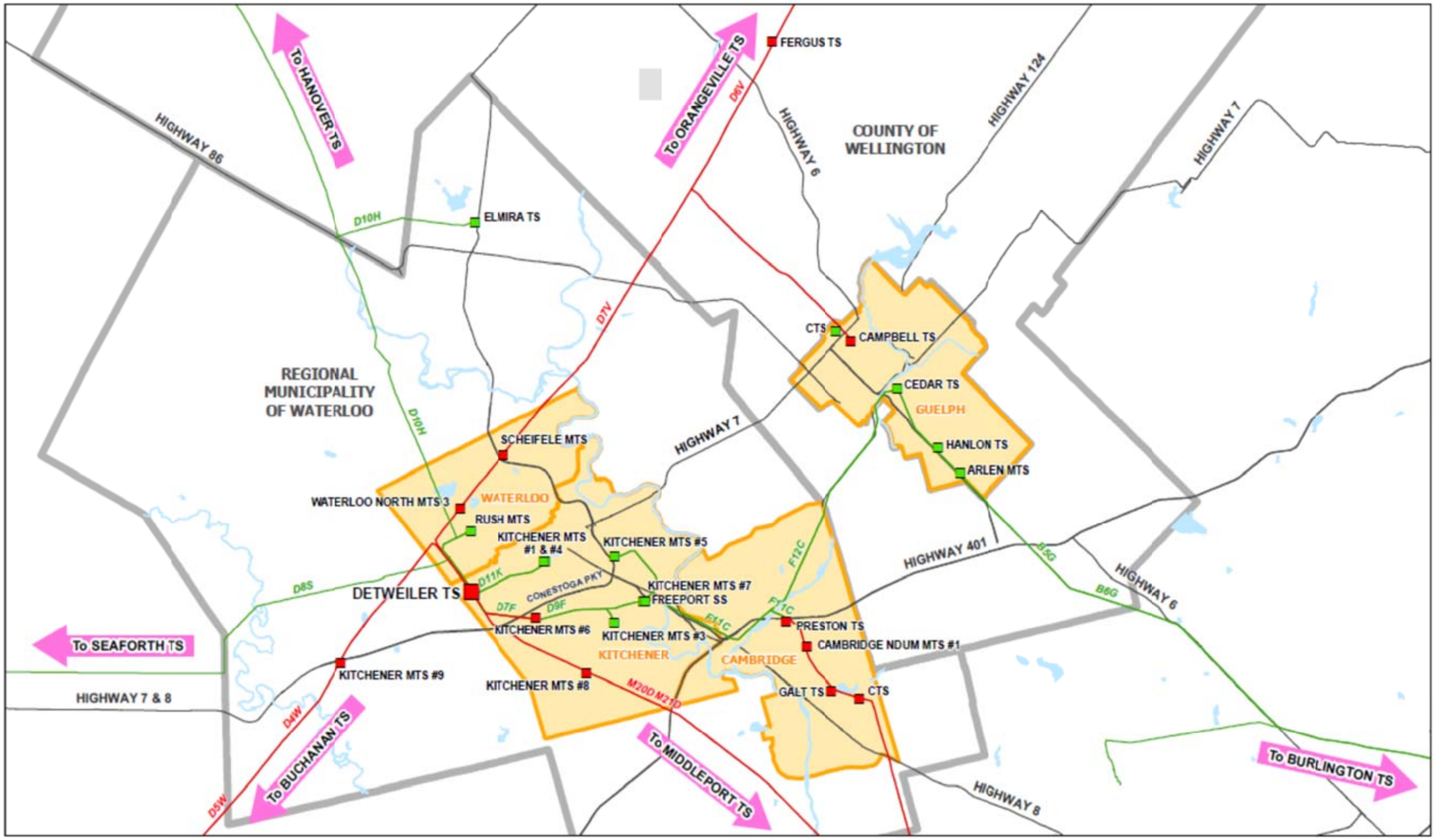
2. Autotransformer T2 at Detweiler TS is expected to be at 104.4% of LTE loading for year 2016 for the following contingency:
    i. Detweiler T4 outage plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS). Since the post-contingency flow is below the auto-transformer STE, operational control actions can be taken to reduce loading to within the LTE rating.

8.0 RECOMMENDATIONS

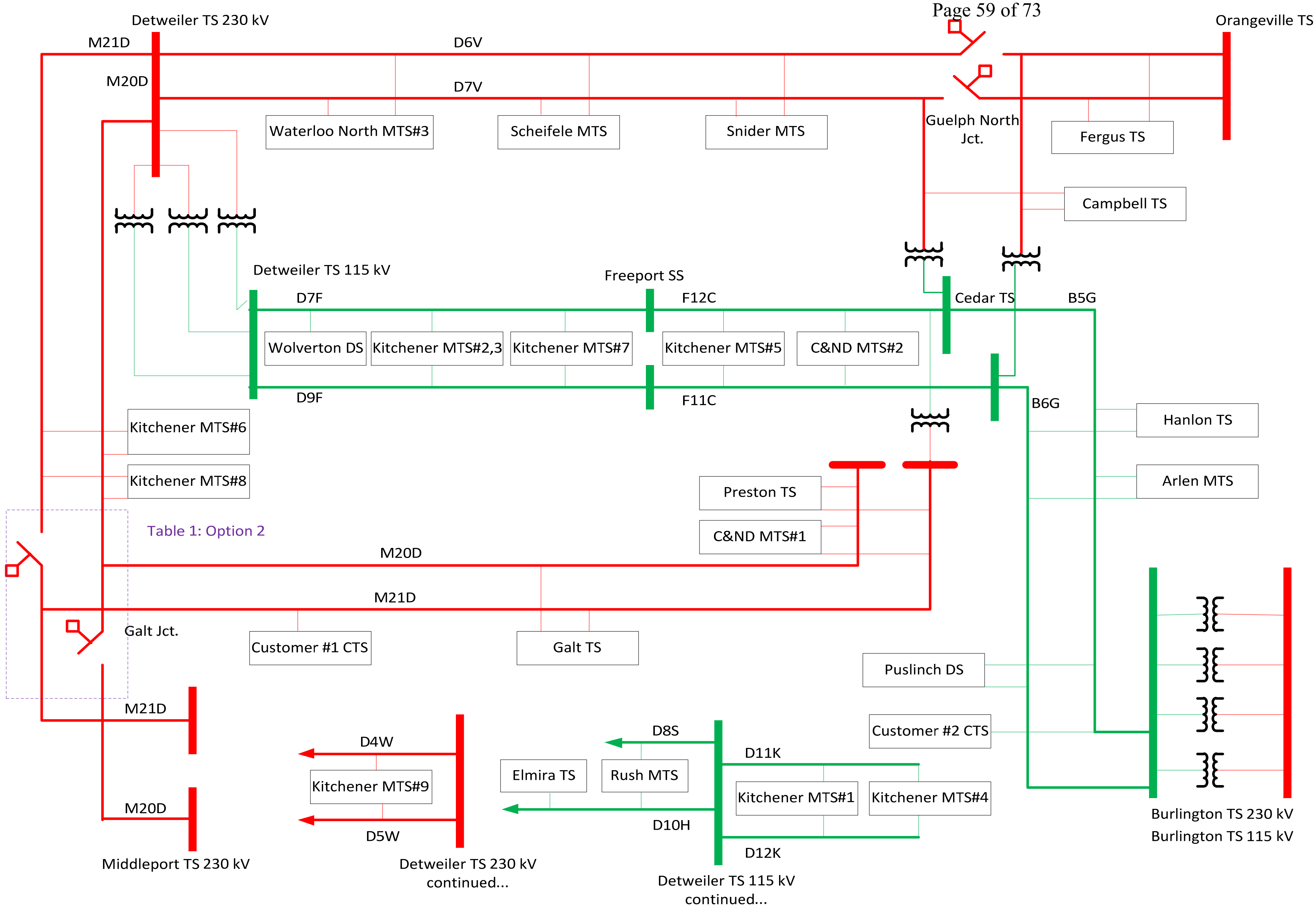
The following recommendations are to address the transmission infrastructure deficiencies within the study period for the KWCG area. These recommendations are:

1. Hydro One Networks to install a set of 230 kV in-line switches onto the main line of circuits M20D and M21D near Galt Junction as soon as possible.
2. Hydro One Networks, the LDCs and the IESO to review the KWCG local area in 2019 with updated KWCG load forecasts to decide on appropriate actions to meet longer-term needs as they emerge.

APPENDIX A: KWCG MAPS



Map 1: Geographical Area of KWCG with Electrical Layout



Map 2: KWCG Electrical Single-Line

APPENDIX B: TRANSMISSION-CONNECTED GENERATION IN THE KWCG AREA

Name	Installed Capacity	Peak Capacity Contribution[5]	Location	Existing or Contracted
Dufferin Wind Farm	97	13.6	Orangeville TS	Existing
Conestoga Wind Farm	67	10.8	D10H	Contracted (future i/s date unknown)

[5] Percentage of installed capacity is 14 % for wind generation

APPENDIX C: KWCG CUSTOMER & LDC LOAD FORECASTS

Table C1: KWCG 2015 RIP Load Forecast*

TS	LDC	Load Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	Planning Demand	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	Planning Demand	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS-Note 1	Cambridge & North Dumfries Hydro	Planning Demand	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Cambridge MTS # 2-Note	Cambridge & North Dumfries Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #6	Kitchener-Wilmot Hydro	Planning Demand	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	Planning Demand	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	Planning Demand	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	Planning Demand	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Kitchener MTS #5	Kitchener-Wilmot Hydro	Planning Demand	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Detweiler TS	Kitchener-Wilmot Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #4	Kitchener-Wilmot Hydro	Planning Demand	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	Planning Demand	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Kitchener MTS #1	Kitchener-Wilmot Hydro	Planning Demand	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Wolverton DS	Hydro One Distribution	Planning Demand	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Fergus TS	Hydro One Distribution	Planning Demand	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Puslinch DS	Hydro One Distribution	Planning Demand	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Cedar TS T1/T2	Guelph Hydro	Planning Demand	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cedar TS T7/T8	Guelph Hydro	Planning Demand	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	Planning Demand	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Arlen MTS	Guelph Hydro	Planning Demand	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	Planning Demand	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	Planning Demand	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo MTS #3	Waterloo North Hydro	Planning Demand	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
Snider MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Bradley MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	Waterloo North Hydro	Planning Demand	30.4	25.1	26.0	25.8	27.4	28.1	28.8	29.6	31.3	31.9	33.6
Rush MTS	Waterloo North Hydro	Planning Demand	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS-Note 3	Customer Tx Stations	Planning Demand	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Tx Stations (Assumed values)	Planning Demand	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Planning demand (MW) = ((Gross-CDM) x Extreme Weather Factor) – DG

*Based upon KWCG 2015 IRRP Planning Load Forecast except where otherwise noted.

Note 1: The LDC has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expect to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

Note 2: The LDC has confirmed that additional transformation capacity (Snider/Bradley TS) would not be required until after 2024. The exact location and timing of these TS's have not been determined at this time. The load growth indicated at Snider and Bradley in the forecast can be managed by existing TS's/impact of CDM/DG in the Waterloo Region. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term. Cambridge #2 is assumed to be supplied off the KWCG 115kV system

Note 3: Slight modification from KWCG 2015 IRRP Planning forecast based on information provided by the transmission-connected customer

Note: Guelph CTS 1 forecast was removed as the LDC confirmed the load was already accounted for within their forecast

APPENDIX D: TECHNICAL RESULTS – LOCAL AREA ANALYSIS

Single element contingencies were considered in order to determine the presence of thermal overload and/or voltage violations.

Table D1: Single Element Contingencies (single zone of protection)

<table>
<tr><th colspan="12">Loss of a Single Circuit (N-1)</th></tr>
<tr><td colspan="2">D11K</td><td colspan="2">D12K</td><td colspan="2">D8S</td><td colspan="2">D10H</td><td colspan="2">D7F</td><td colspan="2">D9F</td></tr>
<tr><td colspan="2">F11C</td><td colspan="2">F12C</td><td colspan="2">B5G</td><td colspan="2">B6G</td><td colspan="2">D4W</td><td colspan="2">D5W</td></tr>
<tr><td colspan="2">M20D*</td><td colspan="2">M21D**</td><td colspan="2">D6V***</td><td colspan="2">D7V****</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><th colspan="12">Loss of a Single Autotransformer (N-1)</th></tr>
<tr><td colspan="2">Detw. T2</td><td colspan="2">Detw. T3♦</td><td colspan="2">Detw. T4♦♦</td><td colspan="2">Cedar T3♦♦♦</td><td colspan="2">Cedar T4♦♦♦♦</td><td colspan="2">Preston T2**</td></tr>
<tr><td colspan="4">Middleport T3♦♦♦♦♦</td><td colspan="4">Middleport T6♦♦♦♦♦♦</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><th colspan="12">Loss of a Single HV Reactive Element (N-1)</th></tr>
<tr><td colspan="3">Detweiler 230 kV cap. bank</td><td colspan="3">Middleport 230 kV cap. bank(K1D1)</td><td colspan="3">Orangeville 230 kV cap. bank</td><td colspan="3">Burlington 230 kV cap. bank</td></tr>
<tr><td colspan="3">Detweiler 230 kV SVC</td><td colspan="3">Middleport 230 kV cap. bank(K2D2)</td><td colspan="3">Detweiler 115 kV cap bank</td><td colspan="3">Burlington 115 kV cap bank</td></tr>
</table>

*M20D (includes Detweiler T3 and Preston T2 via Preston Special Protection Scheme)

**M21D (includes Preston T2)

***D6V (includes Detweiler T4 and Cedar T3)

****D7V (includes Cedar T4)

♦Detweiler T3 (includes circuit M20D and Preston T2 via Preston SPS)

♦♦Detweiler T4 (includes circuit D6V and Cedar T3)

♦♦♦Cedar T3 (includes circuit D6V and Detweiler T4)

♦♦♦♦Cedar T4 (includes circuit D7V)

♦♦♦♦♦Middleport T3 (includes circuit N580M and V586M due to Line End Open)

♦♦♦♦♦♦Middleport T6 (includes circuit N581M and M585M due to Line End Open)

Results: Thermal Overload and Voltage Violations

Table D3: Thermal Analysis (>100% LTE), year 2025

Element	Contingency	%LTE
All circuits and auto-transfers are within ratings		

Table D4: Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX E: TECHNICAL RESULTS – BULK POWER SYSTEM CONSIDERATIONS

Applicable contingencies were considered on BPS elements to establish their impact on the local area.

Table E1: N-2 Contingencies

Loss of a Double Circuit Line (N-2) emanating from a BPS station		
B22D and B23D	D4W and D5W	M20D and M21D
D6V and D7V	--	--
Breaker Failure (B/F) Contingencies at BPS station (N-2)		
Detweiler TS 230 kV bus	B/F of AL6	Loss of: D6V, Cedar T3, Detw T4, M21D, Preston T2
	B/F of AL7	Loss of: D7V, Cedar T4, M21D, Preston T2
	B/F of L7L20	Loss of: D7V, Cedar T4, M20D, Detw T3, Preston T2
	B/F of HT1A	Loss of: M21D, Preston T2, SVC1
	B/F of ACS21	Loss of : M21D, Preston T2, SC21
	B/F of HL20	Loss of: M20D, Detw T3, D5W, SC22
	B/F of T2SC21	Loss of: Detw T2, SC21
	B/F of HT2	Loss of: Detw T2, SC21, D5W
	B/F of DL22	Loss of: B22D, D6V, Cedar T3, Detw T4
Middleport TS 500 kV bus	Covered under Loss of Middleport T3 and T6 autotransformers for the local area analysis (Appendix D)	
Middleport TS 230 kV bus	There are no B/F conditions that would be critical to the supply to the KWCG area.	

Table E2: N-1-1 Contingencies

Loss of a Critical Element, System Adjustment, Loss of a Critical Element (N-1-1)
Loss of: Detw T4 plus Detw T3 (plus M20D by configuration which also includes the loss of Preston T2 via Preston SPS)
Loss of: Preston T2 plus D7V (plus Cedar T4 by configuration)

Note that during the simulations no System Adjustment was afforded; this is considered a conservative approach.

Results: Thermal Overloads and Voltage Violations

As per Table E3 and E5: Detweiler TS 230/115 kV autotransformer T2 will become overloads when Detweiler TS autotransformer T4 is out-of-service followed by the loss of Detweiler TS autotransformer T3 in conjunction with circuit M20D by configuration. Preston TS autotransformer T2 is also removed from service via the Preston SPS.

Table E3: Thermal Analysis (>95% LTE), year 2016

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	104.4 (74.2% STE*) %

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E4: Voltage Analysis, year 2016

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

Table E5: Thermal Analysis (>95% LTE), year 2025

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	114.2 (81.4%STE*)

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E6 Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX F: LOAD SECURITY ANALYSIS

Load connected to each circuit pair that is lost by configuration following an [N-2] double circuit contingency is:

Table F1: Load Lost Due to Configuration, year 2016

Circuit Pair	MW
M20/21D	420
D6/7V	482
D4/5W	34
D7/9F	131
F11/12C	74
B5/6G	105
D11/12K	98
D8S/D10H	89

Table F2: Load Lost Due to Configuration, year 2025

Circuit Pair	MW
M20/21D	489
D6/7V	571
D4/5W	36
D7/9F	141
F11/12C	78
B5/6G	128
D11/12K	103
D8S/D10H	95[6]

Table F1 illustrates that none of the double circuit contingencies result in more than 482 MW of load lost in year 2016.

Table F2 illustrates that none of the double circuit contingencies result in more than 571 MW of load lost in year 2025.

[6] D8S and D10H emanate out of Detweiler TS as a double circuit line however after ~ 5 km they each become a single circuit 115 kV line. Based on their N/O open points, the loss of the double circuit line within the 5 km span out of Detweiler TS, will results in approximately 95 MW of load lost.

Table F3: Two Elements Out of Service

Loss of a Double Circuit Line		
D7F and D9F	F11C and F12C	B5G and B6G
D4W and D5W	M20D and M21D	D11K and D12K
D6V and D6V		

Loss of Two Autotransformers[7]

Station	Detweiler Auto	Preston Auto	Cedar Auto	Burlington Auto
Detweiler Auto	N/A	Detweiler T3 + Preston T2	Cedar T3 + Detweiler T4	Burlington T6 + Detweiler T3
Preston Auto	Detweiler T3 + Preston T2	N/A	Cedar T4 + Preston T2	Burlington T6 + Preston T2
Cedar Auto	Cedar T3 + Detweiler T4	Cedar T4 + Preston T2	Cedar T3 + Cedar T4	Burlington T6 + Cedar T3
Burlington Auto	Burlington T6 + Detweiler T3	Burlington T6 + Preston T2	Burlington T6 + Cedar T3	N/A

Results: Thermal Overload and Voltage Violations

Table F5: Thermal Analysis (>100% STE), year 2025

Element	Contingency	%STE
All circuits and auto-transfers are within ratings		
Element	**Contingency**	**%LTE**
All circuits and auto-transfers are within ratings		

Table F6: Voltage Analysis (> emergency ratings), year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

[7] For stations that have three or more autotransformers connected in parallel typical operating practice after the loss of one autotransformer is to make load transfers to other interconnected autotransformer station(s) such that the remaining load at the affected station would be at or below the station's reduced Limited Time Rating (LTR). It is assumed the in this case that sufficient time between single autotransformer contingencies is available for such load transfers to be carried out by operator response.

APPENDIX G: LOAD RESTORATION ANALYSIS

Restoration of Load Connected to M20/21D

By year 2025 the total forecasted load connected to circuits M20/21D is 489 MW. Loss of this double circuit line would result in the loss of all 489 MW. In order to restore load to these stations at least one circuit would have to be placed back in service**,** noting that to restore Customer #1 CTS circuit M21D must specifically be placed back in service due to the customer's single-circuit transmission-connection

Based on criteria:

Load Required to be Restored	Duration
239MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Existing infrastructure allows for only the restoration of 100 MW of load in approximately 30 min. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period.

Restoration of Load Connected to D6/7V

By year 2025 the total forecasted load connected to D6/7V is 571 MW. Loss of this double circuit line would result in the loss of all 571 MW. As part of the Guelph Area Transmission Reinforcement project, two 230 kV in-line switches will be installed in year 2016 on the main line between Detweiler TS and Orangeville TS at Guelph North Junction. To restore load to these stations, the operator will utilize these switches to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion.

Based on criteria:

Load Required to be Restored	Duration
321MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and

3. the relative distance from the nearest field maintenance centre[8]

the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D4/5W

By year 2025 the total forecasted load connected to D4/5W is 36 MW. Loss of this double circuit line would result in the loss of all 36 MW. To restore load to this station at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
36 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D7/9F

By year 2025 the total forecasted load connected to D7/9F is 141 MW. Loss of this double circuit line would result in the loss of all 141 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
141 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

---

[8] The KWCG area is considered an urban area and as such, access to transmission facilities, repair materials and personnel in order to make a repair within 8 hours is realistic. A Hydro One field maintenance centre is located in Guelph.

Restoration of Load Connected to F11/12C

By year 2025 the total forecasted load connected to F11/12C is 78 MW. Loss of this double circuit line would result in the loss of all 78 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
78 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to B5/6G

By year 2025 the total forecasted load connected to B5/6G is 128 MW. Loss of this double circuit line would result in the loss of all 128 MW. To restore load to Enbridge Westover CTS's circuit B5G must be placed back in service due to the CTS's single-circuit transmission connection. To restore load at the other stations at least one circuit would to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
128 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D11/12K

The total forecasted load serviced by radial circuits D11/12K will not exceed 103 MW by 2025. Loss of this double circuit line would result in the loss of all 103 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
103 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

<u>Restoration of Load Connected to D8S/D10H</u>

The total forecasted load serviced by these radially operated 115 kV circuits will not exceed approximately 95 MW by year 2025. Loss of this double circuit line would result in loss of all 95MW. To restore Rush MTS either circuit can be placed back into service or the station could possibly be fed via circuit L7S out of Seaforth TS; however to restore Elmira TS circuit D10H must be placed back in service due to Elmira TS's single-circuit transmission-connection.

Based on criteria:

Load Required to be Restored	Duration
95 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

APPENDIX H: SUPPLY TO ELMIRA TS AND RUSH MTS

Study Results:

Table H1: Station Capacity: Summer Ratings and Summer Load Forecast

Station	**Transformer Capacity (10-day LTR)**	**Year 2025 Load Forecast**
Rush MTS	69 MVA*	61.3 MW / 69.9 MVA (0.88 pf** at defined meter point, 115 kV side)
Elmira TS	58.5 MVA	33.6 MW / 37.1 MVA*** (0.91 pf at defined meter point, 115 kV side)

*The limiting component is a low voltage cable; when required the limiting component will be modified and the rating to be 75 MVA

** Power factor at the defined meter point improves to 0.92 when 5.4 MVar of installed feeder capacitor banks assumed lumped at the LV bus and results in 66.8 MVA loading

*** A 9.2 MVar @ 27.6 kV shunt capacitor bank is installed at Elmira TS not in-service; when in-service power factor improves and loading through the transformers decrease.

Table H2: Transmission Capacity of circuits D8S and D10H

Year	**Contingency**	**D10H – Detweiler TS x Waterloo Jct.**	**D8S – Detweiler TS x Leong Jct.**
		590 A Continuous *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*	*590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*
2016	Pre	287 A	285 A
	Loss of D8S	454 A	--
	Loss of D10H	--	459 A
2025	Pre	319 A /	302 A
	Loss of D8S	511	--
	Loss of D10H	--	500 A

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Table H3: Voltage Profile at Rush MTS and Elmira TS

Year	Contingency	Rush MTS 115 kV D8S	Rush MTS 115 kV D10H	Rush MTS 13.8 kV	Elmira TS 115 kV	Elmira TS 27.6 kV
2016	Pre	122.2	122.2	14.4	120.8	27.2
	Loss of D8S	--	121.8	13.7	120.6	27.1
	Loss of D10H	121.5	--	13.7	--	--
2025	Pre	123.2	123.1	14.2	121.6	27.3
	Loss of D8S	--	122.6	13.6	121.1	27.2
	Loss of D10H	122.4	--	13.6	--	--

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Analysis:

D8S

Circuit D8S has a normally open point at St. Mary's TS separating the circuit from circuit L7S. D8S normally supplies half the load at Rush MTS and half the load at St. Mary's TS. The other half of the load at Rush MTS is normally supplied by circuit D10H and the other half of the load at St. Mary's TS is normally supplied by L7S. Referring to Table H2, for the loss of circuit D10H, circuit D8S has sufficient capacity to supply all load at Rush MTS and St. Mary's TS for year 2025 and beyond.

D10H

Circuit D10H runs between Detweiler TS and Hanover TS and has a normally open point between Elmira TS and Palmerston TS. Elmira TS is normally supplied from Detweiler TS while Palmerston TS is normally supplied from Hanover TS. Referring to Table H2, D10H has sufficient capacity to supply all load at Elmira TS for year 2025 and beyond. When circuit D8S is out of service, D10H has sufficient capacity to supply all load at Elmira TS and Rush MTS (while St. Mary's TS is supplied by circuit L7S).

Rush MTS

Since this station is a Municipal owned station, Waterloo North Hydro is to ensure there is sufficient transformation capacity to accommodate load growth. According to load forecasts and referring to Table H1, over the next 10-years load will fluctuate above and below the year 2025 forecast but will be remain within the station's Limited Time Rating (LTR). Waterloo North Hydro is to inform Hydro One if the connection requires modification and/or if a new station connection is required in order to accommodate load growth. Waterloo North Hydro has already incorporated their future Snider MTS and Bradley MTS into the KWCG regional plan to cater for load growth.

Rush MTS is supplied by two 115 kV circuits, D8S and D10H. Referring to Tables H2 and H3, when one of these circuits is out of service, the voltage profile at Rush MTS is healthy and the other circuit has sufficient capacity to supply all load to Rush MTS.

Elmira TS

According to the forecast and referring to Table H1, transformers at Elmira TS have sufficient capacity for year 2025 loading and beyond.

Elmira TS is supplied by one 115 kV circuit, D10H. Referring to Tables H2 and H3, the voltage profile at Elmira TS is healthy and the circuit has sufficient capacity to supply load to Elmira TS for year 2025 loading and beyond.

When circuit D10H out of Detweiler TS is unavailable, Elmira TS may also be supplied by D10H out of Hanover TS (by closing the normally open point between Palmerston TS and Elmira TS). Assuming Palmerston TS is at its forecasted year 2025 normal weather peak load, approximately 25 MW of load at Elmira TS may be supplied out of Hanover TS. The limiting factor being the 115 kV voltage profile on D10H as Elmira TS is nearly 80 circuit km from Hanover TS.

Metro Toronto

REGIONAL INFRASTRUCTURE PLAN

January 12, 2016

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Prepared by:
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With support from:

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Enersource Hydro Mississauga
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
PowerStream Inc.
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Veridian Connections Inc.

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DISCLAIMER

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

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

Working Group 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 RIP 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 RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP 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 RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

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

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PowerStream Inc.
- Toronto Hydro-Electric System Limited ("THESL")
- Veridian Connections Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the regional planning process and it follows the completion of the Central Toronto Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the and Metro Toronto Northern Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for both the Central Toronto Sub-Region and Metro Toronto Northern Sub-Region that make up the Metro Toronto Region.

The Central Toronto IRRP has identified longer term needs beyond 2025. These longer term needs are also reviewed and discussed in this report. However, as the need dates are beyond 2025, adequate time is available to develop a preferred alternative in the next planning cycle expected to be started in 2018.

The major infrastructure investments planned for the Metro Toronto Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost ($M)
1	Manby Autotransformer Overload Protection Scheme	2018	$2
2	Runnymede TS Expansion & Manby x Wiltshire Corridor Upgrade	2019	$90
3	Horner TS Expansion	2020	$53
4	Richview x Manby Corridor Upgrade	2020	$20-40
5	Copeland MTS Phase 2	2020+	$46

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As mentioned above, the next planning cycle is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE METRO TORONTO REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) on behalf of the Working Group that consists of Hydro One, Enersource Hydro Mississauga, Hydro One Networks Inc. Distribution, the Independent Electricity System Operator (“IESO”), PowerStream Inc., Toronto Hydro-Electric System (“THESL”), and Veridian Connections Inc. in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Metro Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty five 230kV and 115kV transmission and step-down stations as shown in Figure 1-1. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The summer 2015 area load of the Metro Toronto region was about 4700MW.

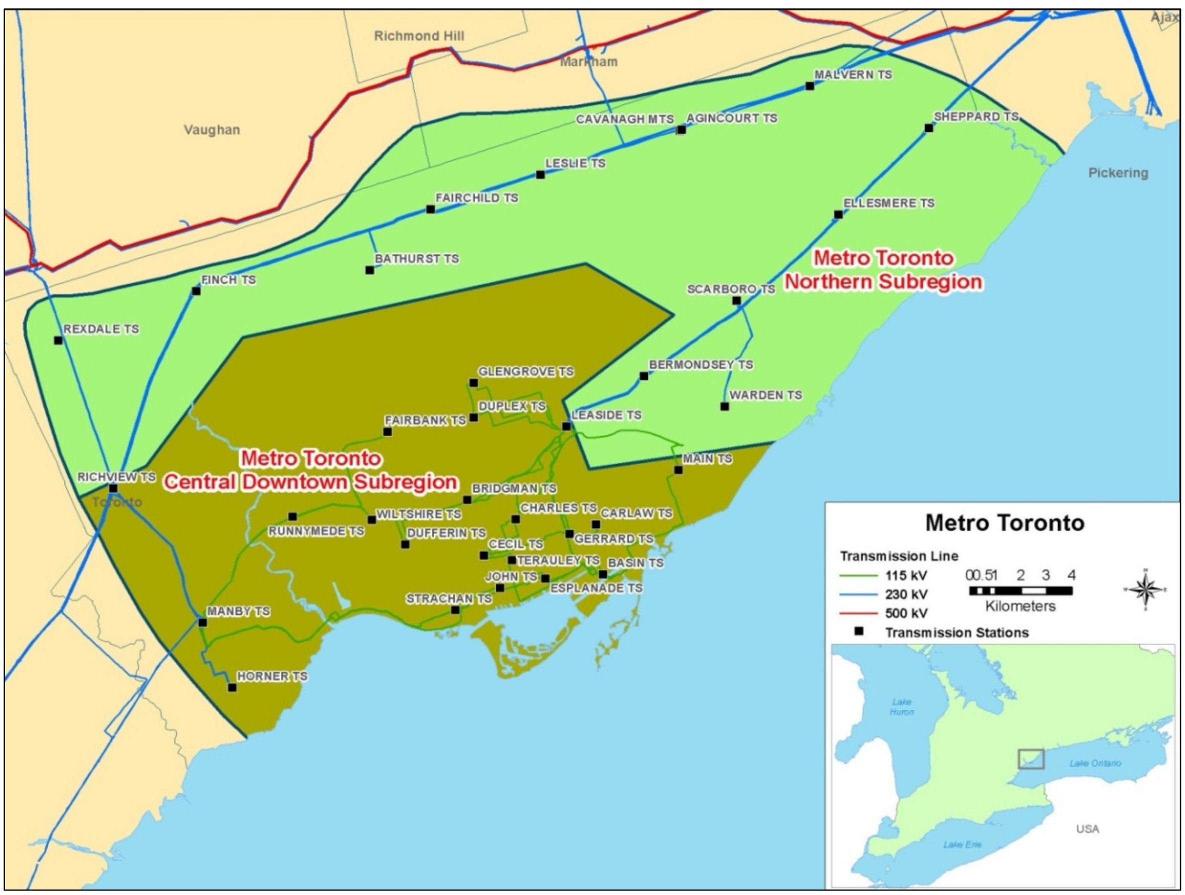

Figure 1-1 Map of Metro Toronto Region

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region. For the Metro Toronto Region, community engagement through a formal LAC is on-going.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

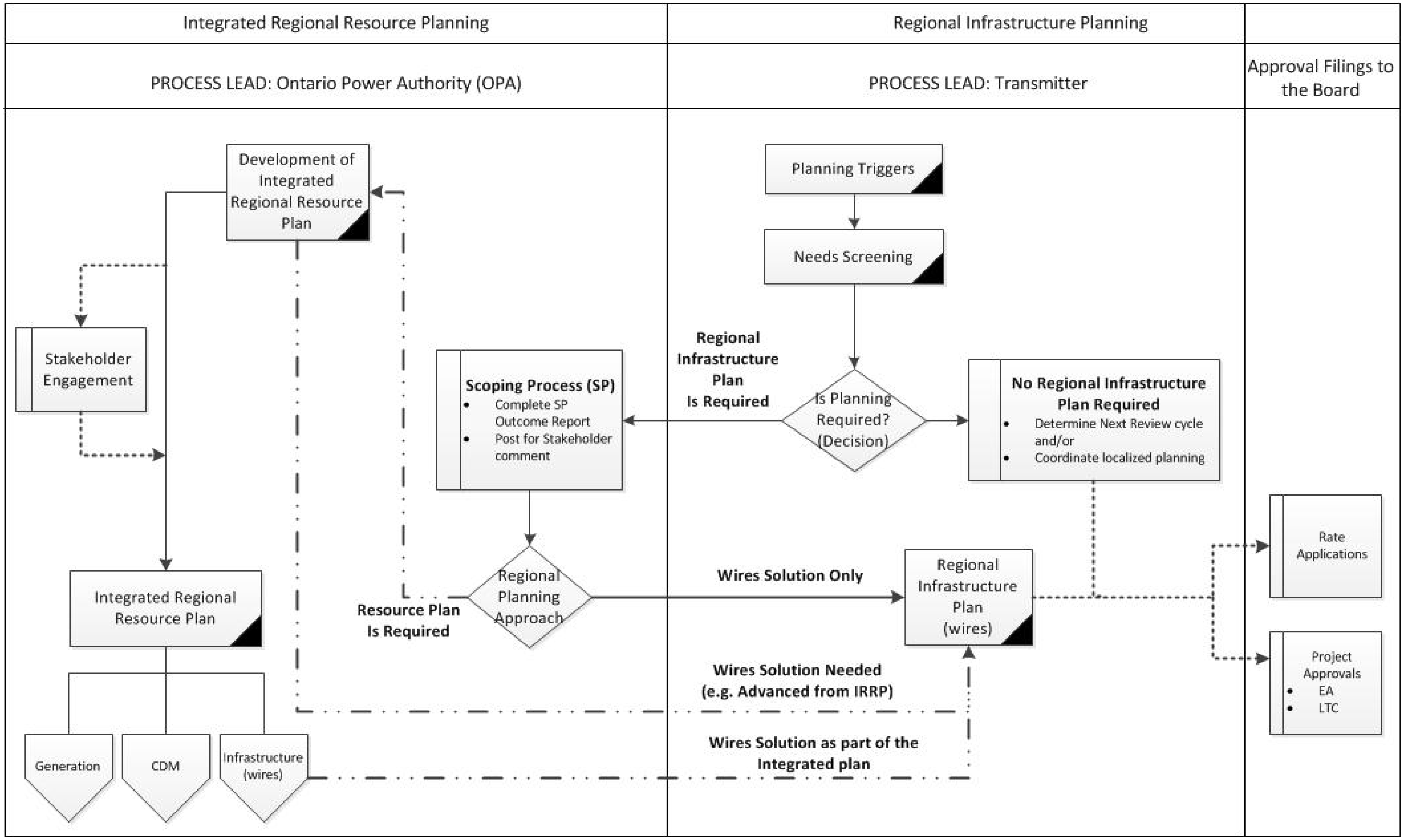

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

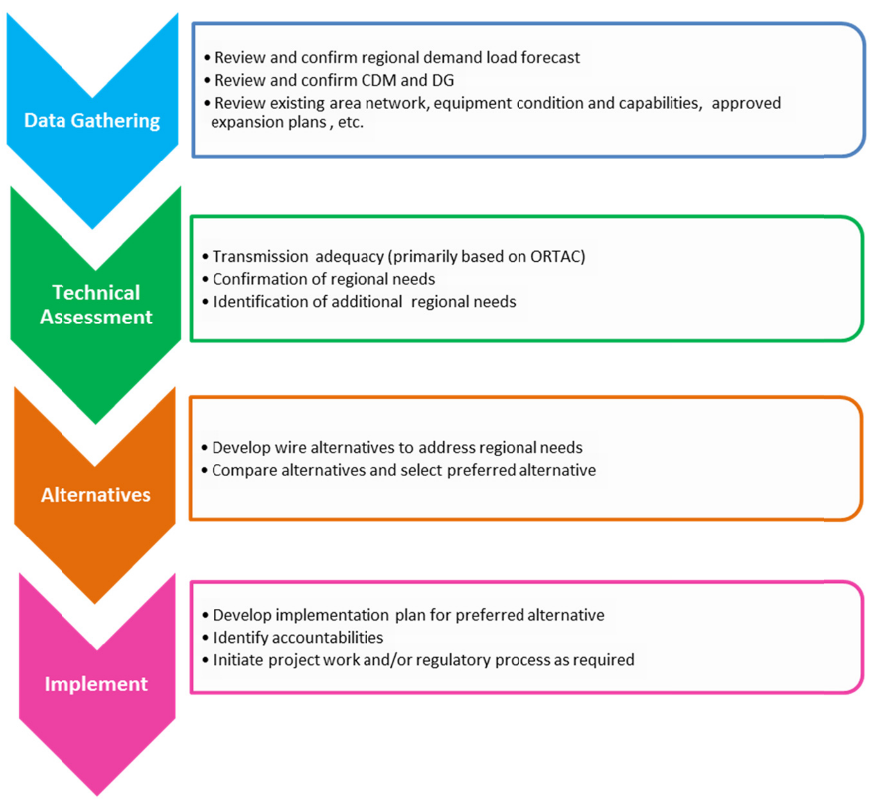

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE METRO TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Metro Toronto Region is provided through three 500/230 kV transformers stations - Claireville TS, Cherrywood TS and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near downtown area and connected to the 115 kV network at Hearn Switching Station. The Metro Toronto Region 2015 peak summer demand was about 4700MW which represents about 20% of the gross electrical demand in the province.

Toronto Hydro-Electric System Limited ("THESL") is the Local Distribution Company ("LDC") that serves the electricity demands for the city of Toronto. Other LDCs supplied from electrical facilities in the Metro Toronto Region are Hydro One Networks Inc. Distribution, PowerStream Inc., Veridian Connections Inc., and Enersource Hydro Mississauga. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Central Toronto Area which included the 115kV network and the 230kV facilities in the western part of Region. The June 2014 Metro Toronto Northern Sub-Region Needs Assessment report, prepared by Hydro One, considered the remainder of the Metro Toronto region. A map and a single line diagram showing the electrical facilities of the Metro Toronto Region, consisting of the two sub-regions, is shown in Figure 3-1 and Figure 3-2 respectively. Please note that the facilities shown include the new Leaside TS to Bridgman TS 115kV circuit L18W and the new Copeland MTS. The L18W circuit is being built as part of the Midtown Transmission Reinforcement Project and Copeland MTS is a new THESL owned transformer station to serve the downtown area. Work on these projects is in the advanced stage and both are expected to come into service in 2016.

3.1 Central Toronto Sub-Region

The Central Toronto Sub-Region includes the area extending northward from Lake Ontario to roughly Highway 401, westward to Highway 427 and Etobicoke Creek, and eastward to Victoria Park Avenue.

The Central Toronto Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

The Central Toronto Sub-region is further subdivided into two areas:

- The Richview Manby 230kV area: This includes the former borough of Etobicoke and is served by the Richview TS to Manby TS 230kV circuits. The area has two 230/27.6kV step-down transformer stations. The coincident peak summer 2015 area load was about 320 MW.
  The Richview TS to Manby 230kV circuits together with the Richview TS to Cooksville TS circuit R24C supply a number of stations in the GTA West Southern Sub-Region. These stations while outside the Metro Toronto Region have therefore been included in Figure 3-2.

- The Central 115kV Area: The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS), fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The area includes the downtown core including the financial, entertainment and educational districts. The 2015 summer coincident area load was about 1900MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Metro Toronto Northern Sub-Region

The Metro Toronto Northern Sub-Region comprises the remainder of the Metro Toronto region. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr.

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS 230kV transmission system. The area is served primarily at 27.6kV by fifteen step-down transformer stations with a pocket of 13.8kV load supplied from Leaside TS and Leslie TS. The 2015 summer coincident area load was about 2500 MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

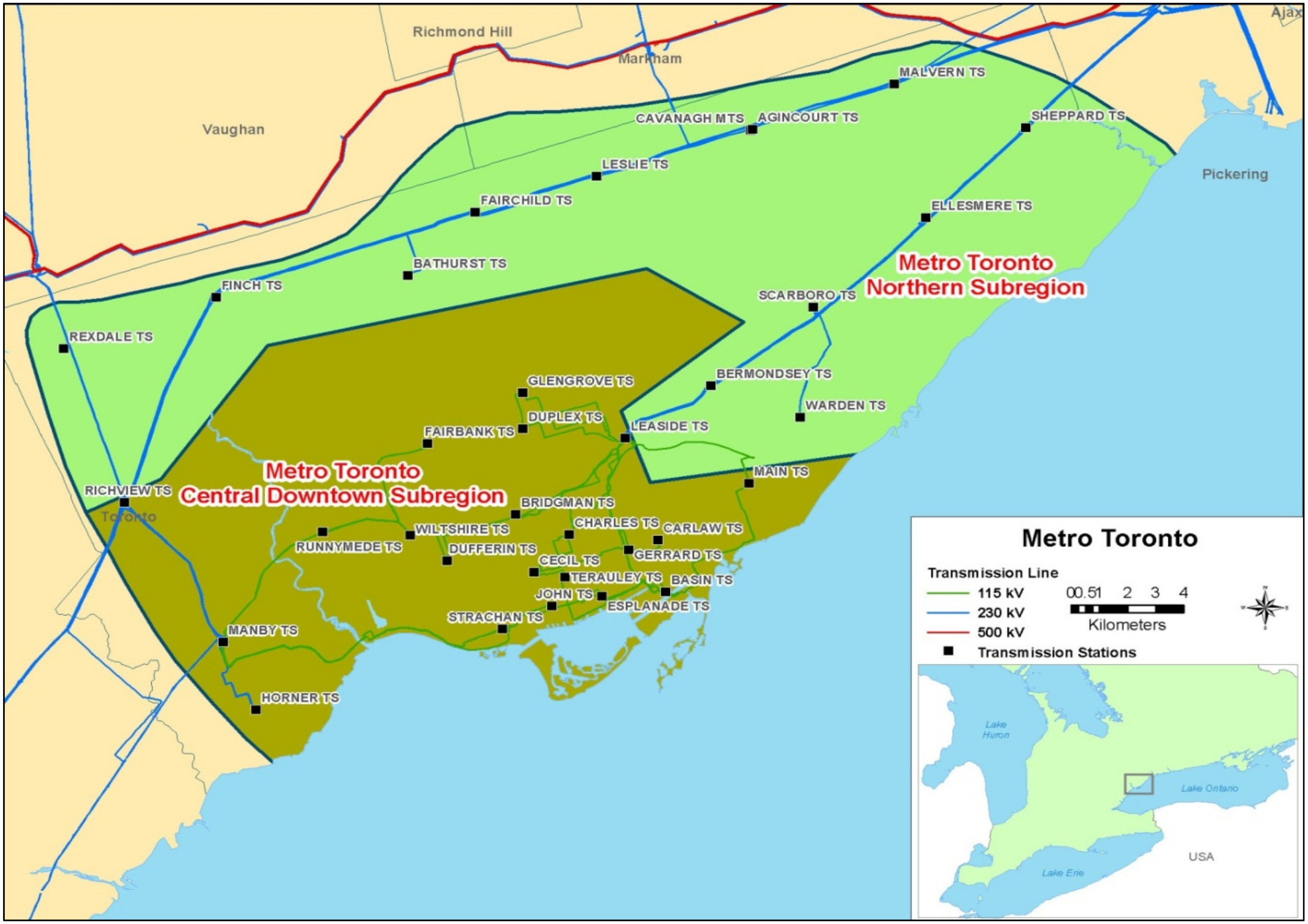

Figure 3-1 Metro Toronto Region – Supply Areas

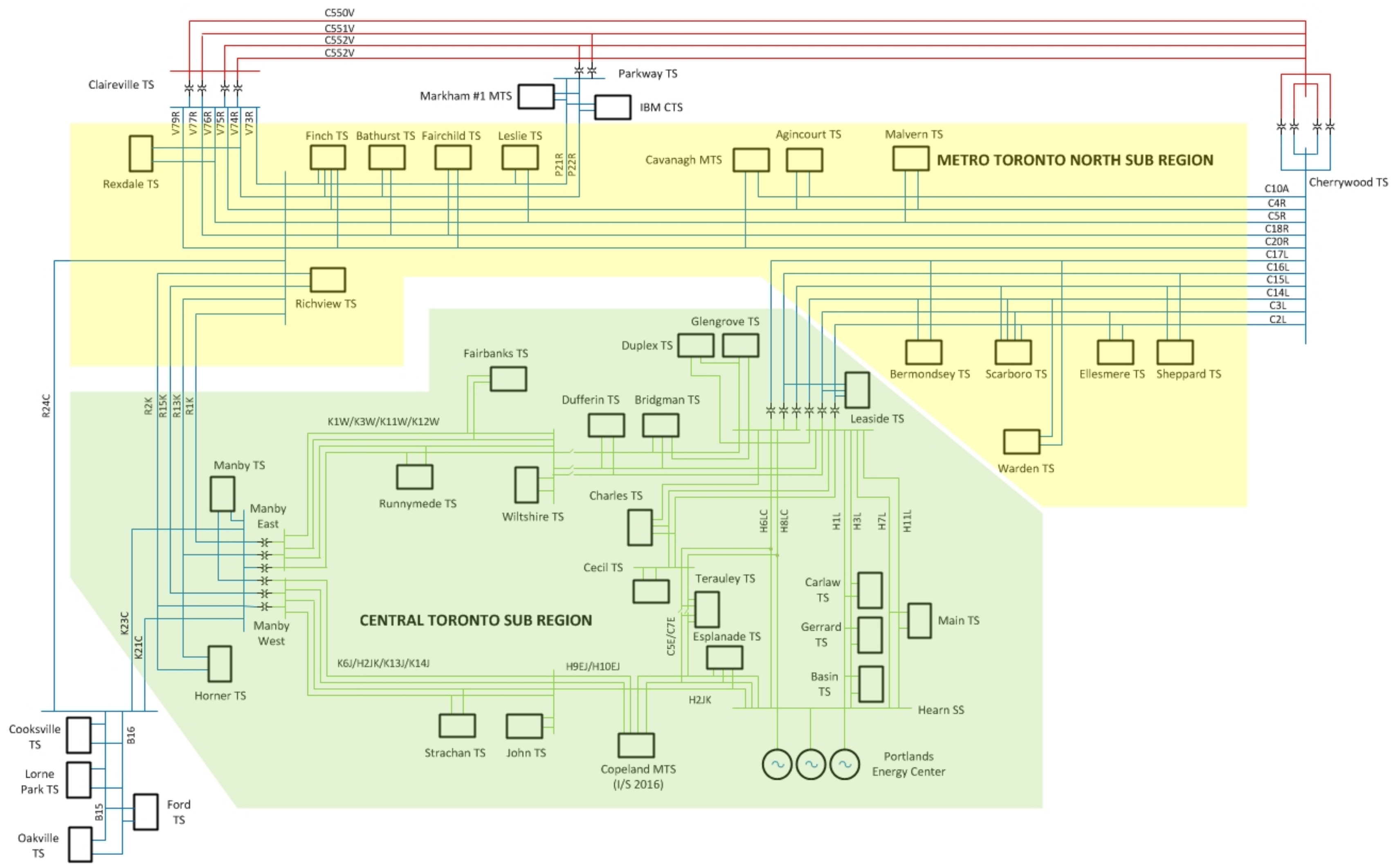

Figure 3-2 Metro Toronto Region – Single Line Diagram

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

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE METRO TORONTO REGION IN GENERAL AND THE TORONTO 115 KV NETWORK IN PARTICULAR.

These projects together with the new 550 MW Portlands Energy Centre that went into service in 2009 have ensured that the City continues to receive adequate and reliable supply. A brief listing of these projects is given below:

- Parkway 500/230 kV TS (2005) – built to provide adequate 500/230 kV transformation capacity following the retirement of Lakeview GS. The station while just outside the Metro Toronto Region is a key contributor in ensuring supply adequacy to the Region.
- John TS to Esplanade TS underground cable circuits (2008) – built to provide transfer capability between the Leaside TS and the Manby TS 115 kV areas.
- Incorporation of the 550 MW Portlands Energy Centre (2009) – covered modification to the Hearn 115kV switchyard to connect the new generation.
- 115 kV Switchyard Work at Hearn SS, Leaside TS & Manby TS (2013 & 2014) – covered replacement of the aging 115 kV switchyard at Hearn SS with a new GIS switchyard and replacement of all 115 kV breakers at Leaside TS and Manby TS.
- Manby 230 kV Reconfiguration (2014) – re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance / improve the distribution of loading on the 230 kV Richview TS to Manby TS system.
- Lakeshore Cable Refurbishment project (2015) – covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.
- Midtown Transmission Reinforcement Project (expected completion by 2016) – covered replacement of the aging L14W underground cable and building an additional fourth 115 kV circuit between Leaside TS and Bridgman TS.
- Clare R. Copeland 115kV switching station (expected completion by 2016) – built to connect a new THESL owned 115/13.8 kV step-down transformer station in the downtown district.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Metro Toronto Region is forecast to increase at an average rate of approximately 0.9% annually up to 2020, at 0.67% between 2020 and 2025 and at 0.61% beyond 2025. The growth rate varies across the region – from about 0.35% in the Northern Sub-Region to 1.07% in the City's downtown area over the 20 years.

Figure 5-1 shows the Metro Toronto Region's planning load forecast (summer net, non-coincident and regional-coincident extreme weather peak) under the IRRP high growth scenario. The regional-coincident (at the same time) forecast represents the total peak load of the 35 step-down transformer stations in the Metro Toronto. The coincident regional peak load is forecast to increase from 5176 MW in 2015 to 6196 MW by 2035.

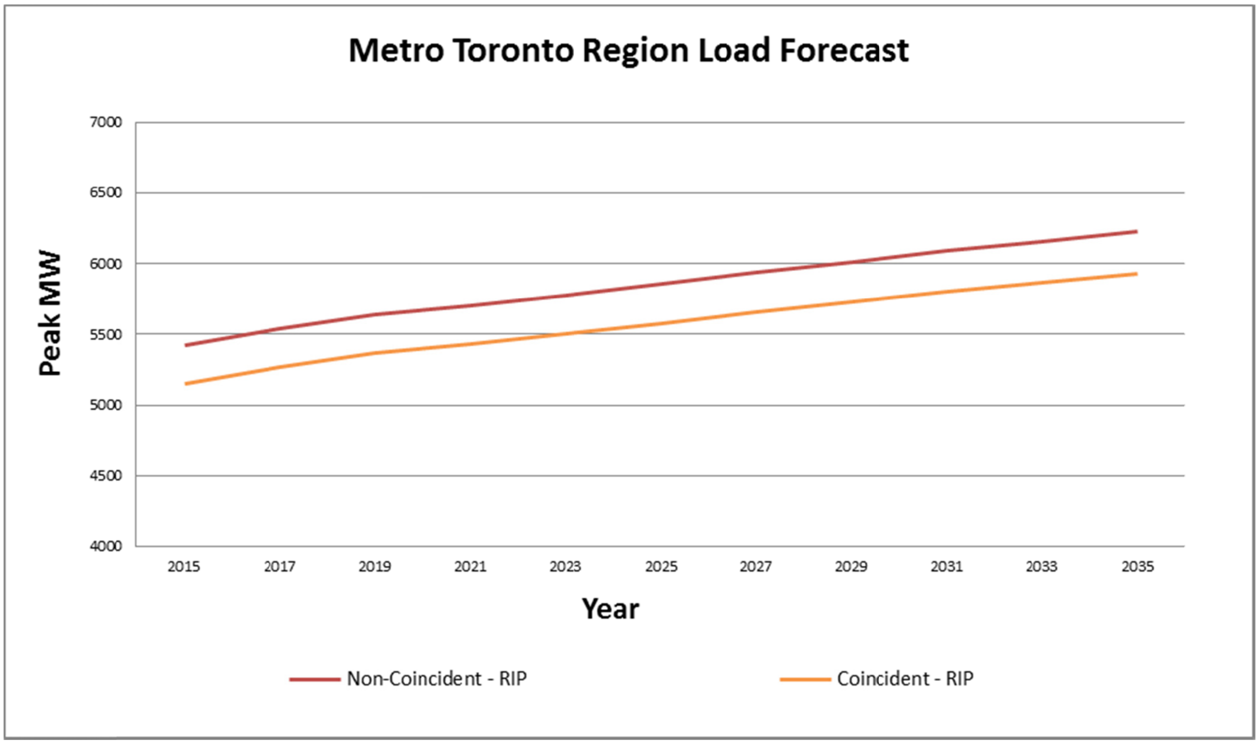

Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast

The coincident and non-coincident extreme weather peak load forecast for the individual stations in the Metro Toronto Region is given in Appendix D. The coincident forecast represents the sum of the area stations peak load at the time of Metro Toronto Region peak demand and represents loads that would be seen by transmission lines and autotransformer stations and is used to determine the need for additional line and auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for station capacity.

The individual station forecasts were developed by projecting 2015 summer peak loads, corrected for extreme weather, using the area stations growth rates as per the 2015 IESO's IRRP study (High Demand Scenario) for the Central Toronto Sub-Region [1] and as per the 2014 Hydro One's Need Assessment study [2] for the Metro Toronto Northern Sub-Region. The growth rates from [1] only account for existing Distributed Generation ("DG"), and do not include any new CDM and DG. The growth rates from [2] are the net growth rates seen by station equipment and account for CDM measures and connected DG. Details on the CDM and connected DG are provided in [1] and [2] and are not repeated here.

Impact of Metrolinx Go Transit Electrification

In June 2015, Metrolinx advised Hydro One that they are planning to proceed with the electrification of the Go transit rail system. This information was provided after the IRRP was completed in April 2015. Under their plan three Traction Power Stations (TPS) are proposed to be built in the Metro Toronto Region. These stations are as follows:

- Mimico TPS – For the Lakeshore West Go Transit Line (2020)
- Cityview TPS – For the Pearson Airport and Kitchener Go Transit lines (2020)
- Warden TPS – For the Lakeshore East Go Transit Line (2020)

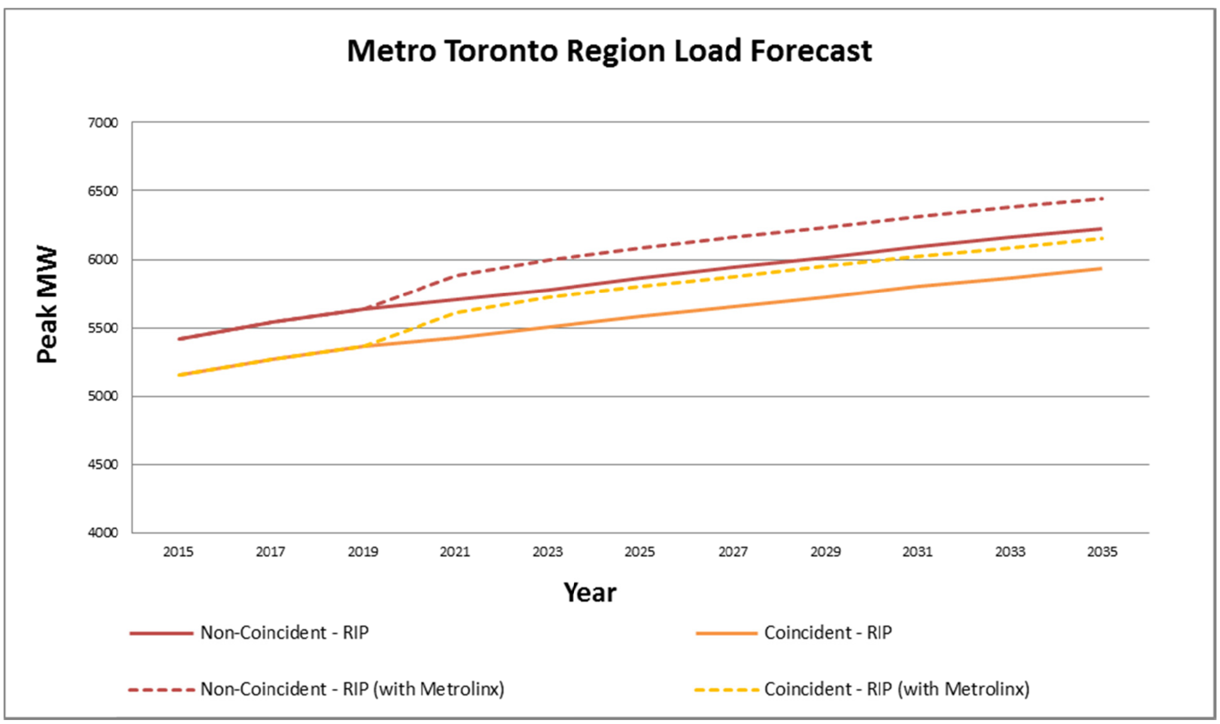

Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load

The impact of the Metrolinx load on the regional forecast is shown in Figure 5-2. Each of the three Metro area stations is expected to have an initial load of 40MW increasing to 80MW in 4 years. The net result is to increase the Region peak load by 240MW.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- For THESL 13.8kV stations, an additional 95% factor is applied to the normal planning supply capacity in this study. This is to reflect the fact that all the capacity cannot be effectively utilized due to the large relative size of the individual customer loads.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE METRO TORONTO REGION OVER THE 2015-2035 PERIOD. IT ASSUMES THAT ALL PROJECTS CURRENTLY UNDER WAY ARE IN SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Metro Toronto Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's Central Toronto Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – Metro Toronto – Northern Sub-Region – June 11, 2014[2]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demands. These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed by a LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Metro Toronto Region was also carried out as part of the RIP report using the latest Regional Forecast based on the IRRP high load growth scenario and as given in Section 5. The impact of Metrolinx Electrification on the regional infrastructure has been included.

For cases where a need was identified in the near or mid-term by the high growth scenario, a sensitivity analysis was done using the IRRP low growth scenario to get a range on the need date. Sections 6.1 to 6.2 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	West Toronto (Runnymede TS & Fairbank TS)	Today
	7.2	Southwest Toronto (Manby TS & Horner TS)	2020-2027
	7.3	Downtown District (JETC(1) Area)	2020+(2)
Transmission Line Capacity	7.4	230 kV Richview TS to Manby TS Corridor	2020-2023
	7.5	Circuit C10A (Duffin Jct. to Agincourt Jct.)	Completed
Supply Security, Reliability and Restoration	7.6	Breaker failure contingencies at Manby W and Manby E TS	2018/2021
	7.7	Breaker failure contingency at Leaside TS	Today
	7.8	Double circuit contingencies C2L/C3L or C16L/C17L (Cherrywood TS to Leaside TS)	2021
	7.9	Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)	Today
Long-Term	7.10	115 kV Manby West To Riverside Jct. Lines	2035+
		230/115 kV Manby TS transformer capacity	2035+
		230/115 kV Leaside TS transformer capacity	2026+
Additional Long-Term Need Identified in RIP	7.10	Leaside TS x Wiltshire TS circuits	2034

(1) JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.
(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

6.1 Metro Toronto Northern Sub-Region

6.1.1 230kV Transmission Facilities

The Northern 230kV facilities consist of the following 230kV transmission circuits (Please refer to Figure 3-2):

a) Claireville TS to Richview TS 230kV circuits: V72R, V73R, V74R, V76R, V77R and V79R.
b) Cherrywood TS to Richview TS 230kV circuits: C4R, C5R, C18R and C20R.
c) Parkway TS to Richview 230kV circuits: P21R and P22R
d) Cherrywood TS to Agincourt TS 230kV circuit C10A.
e) Cherrywood TS to Leaside TS 230kV circuits: C2L, C3L C14L, C15L, C16L and C17L.

The Claireville TS to Richview TS circuits, the Cherrywood TS to Richview TS circuits and the Parkway TS circuits to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh TS. The Need Assessment for the Metro Toronto Northern Sub-Region had identified that line capacity was restricted due to inadequate clearance from underbuilt street lighting and distribution line. Field surveys carried out by Hydro One have confirmed that the limiting underbuilds have been removed. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230kV circuits supply the Leaside TS 230/115kV autotransformers as well as serve local area load. Loading on these circuits is adequate over the study period.

6.1.2 Step-Down Transformer Station Facilities

The Sub-Region has the following step down transformer stations:

Agincourt TS	Leaside TS
Bathurst TS	Leslie TS
Bermondsey TS	Malvern TS
Cavanagh MTS	Rexdale TS
Ellesmere TS	Scarboro TS
Fairchild TS	Sheppard TS
Finch TS	Warden TS

The Metro Toronto Northern Sub-Region Needs Assessment Report had identified that the gross load was approaching station capacity at Cavanagh MTS and the Leslie TS (T1/T2, 27.6kV windings) and the Sheppard TS (T3/T4) DESN units. No action was recommended as the net load after considering the CDM and DG program is within ratings. The RIP report has reviewed the station loading and confirms that station capacity is adequate over the study period. However, the station loads will be monitored to ensure facility ratings are not exceeded.

6.2 Central Toronto Sub-Region

6.2.1 230kV Transmission Facilities

The 230kV transmission facilities in the Central Toronto Sub-Region are as follows (Please refer to Figure 3-2):

a) Richview TS x Manby TS 230kV circuits: R1K, R2K, R13K and R15K
b) Cooksville TS x Manby TS 230kV circuits: K21C/K23C
c) Manby TS 230/115kV autotransformers
d) Leaside TS 230kV/115kV autotransformers

The Richview TS to Manby TS circuits and the Cooksville TS to Manby TS circuits supply the Manby 230/115kV autotransformer station as well as Horner TS. Please note that the K21C and K23C circuits connect back to Richview TS through Cooksville TS and 230kV circuit R24C.

Table 6-2 summarizes the result of adequacy studies and gives the need date for transmission reinforcement for each of the above facilities.

Table 6-2 Adequacy of 230kV Transmission Facilities

Facilities	2015 MW Load(1)	MW Load Meeting Capability (LMC)	Limiting Contingency	Need Date
Richview x Manby 230kV Corridor	1456	1540	R2K	2020-2023(2)
Manby E. 230/115kV autos	330	560	T2	2035+
Manby W. 230/115kV autos	397	612	T9	2035+
Leaside 230/115kV autos + Portlands GS(1)	1340	1525-1915(3)	None	2026+(4)

(1) The loads shown have been adjusted for extreme weather.

(2) The 2020 and 2023 need dates correspond to the high growth and low growth rate scenarios without considering Metrolinx Mimico TPS. Assuming Metrolinx Mimico TPS comes into service in 2020, the need date will become 2020 under both scenarios.

(3) The Leaside 115kV area is supplied by the Leaside TS 230/115kV autotransformers and the 550MW Portlands GS. Load Meeting capability is dependent on the generation from Portlands GS which backs up the flow through the Leaside autotransformers. The 1525MW LMC assumes only 160MW generation at Portland GS while the 1915MW LMC assumes the full 550MW generation at Portland GS.

(4) The need date is based on the 1525MW LMC which assumes that two of the three units are out at Portlands GS and total plant generation is 160MW.

6.2.2 115kV Transmission Facilities

The 115kV facilities in the Metro Toronto Region (see Figure 3-2) can be divided into five main corridors:

1. Manby TS East x Wiltshire TS – Four circuits K1W, K3W, K11, K12W. Forecast loading can exceed corridor rating under certain conditions. More details are provided in Section 7.1.2.
2. Manby TS West x John TS – Four circuits H2JK, K6J, K13J and K14J. These circuits are adequate over the study period.
3. Leaside TS x Hearn TS – Six circuits H6LC, H8LC, H1L, H3L, H7L and H11L. These circuits are expected to be adequate over the study period. .
4. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C. These are expected to be adequate over the study period.
5. Leaside TS x Wiltshire TS – Four circuits L13W/L14W/L15/L18W. The L18W circuit is expected to go into service in summer 2016. Loading will exceed corridor rating by 2034 for loss of the L18W circuit. More details are provided in Section 7.10.4.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Overloaded Sections of 115kV circuits

Facilities	2015 MW Load	MW Load Meeting Capability	Limiting Contingency	Need Date
Manby TS x Wiltshire TS 115kV Corridor	330	348/410(1)	K11W	2019-2023(1)
Leaside TS x Wiltshire TS	310	350	L18W	2034

(1) The Manby x Wiltshire corridor provides emergency backup for Dufferin TS load under Leaside area contingencies. Assuming that a 100MW of back up capability is provided, the maximum load that can be supplied in the Fairbanks/Runnymede area is 348MW and the need date for upgrading the corridor is 2019. If 75MW of back up capability is required, the need date will become 2023. However, if back up capability during peak is not considered, maximum load meeting capability is 410MW. The need in this case would be beyond 2035.

6.2.3 Step-Down Transformer Facilities

There are a total of 20 step-down transformers stations in the Central Toronto Sub Region.as follows:

Basin TS	Esplanade TS	Fairbank TS
Bridgman TS	Gerrard TS	Copeland MTS
Carlaw TS	Glengrove TS	John TS
Cecil TS	Main TS	Strachan TS
Charles TS	Terauley TS	Horner TS
Dufferin TS	Wiltshire TS	Manby TS
Duplex TS	Runnymede TS	

The stations non-coincident loads are given in Appendix D Table D-1. The areas and the stations requiring relief are given in Table 6-4.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
West Toronto: Fairbanks TS and Runnymede TS	285	291	Now
Southwest Toronto : Manby TS and Horner TS area	400	376	2020-2027 (1)
Downtown Toronto: John TS, Esplanade TS, Terauley TS and Copeland MTS (JETC)	739	632	2020+ (2)

(1) The need dates are based on high and low demand growth rates scenario
(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE METRO TORONTO REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP FOR THE CENTRAL TORONTO SUB-REGION [1] AND THE NA FOR THE METRO TORONTO NORTHERN SUB-REGION [2] AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 West Toronto Area

7.1.1 Station Capacity - Runnymede TS & Fairbank TS

Runnymede TS and Fairbank TS are 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. The two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. THESL has managed growth by transferring loads to adjacent area stations.

The area 2015 extreme weather peak load was 291 MW and exceeded the stations capacity of 285MW. The area is experiencing some re-development and the proposed Eglinton Crosstown Light Railway Transit ("LRT") project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. Additional step down transformation capacity is required now to provide relief and be able to meet the forecast load demand.

7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits

The Manby TS x Wiltshire TS four circuit 115kV tower line carries circuits K1W, K3W, K11W and K12W. These circuits supply Fairbanks TS, Runnymede TS and well as Wiltshire TS. Under Leaside area outage conditions, these circuits are also used to pick up all or parts of Dufferin TS and/or Bridgman TS loads. The total corridor capability is dependent on the Fairbanks TS and Runnymede TS load and the load picked up and is given in table below:

Table 7-1 Manby x Wiltshire Corridor Capability

Year	Fairbanks TS, Runnymede TS, and Wiltshire TS Load Forecast (MW)	Amount of Dufferin TS and Bridgman TS Load that can be picked up (MW)	Total Corridor Capability (MW)
2015	330	120	450
2019	349	97	446
2023	375	68	443
2027	390	46	436
2031	399	25	424
2035	406	10	416

The timing of the Manby TS x Wiltshire TS circuits upgrade is dependent on the backup capability desired. If backup capability is not considered, the upgrade can be deferred to beyond 2035. However, if at least 70MW of back up capability - equal to about half of Dufferin TS load - is deemed appropriate, the upgrade would be deferred to about 2023.

Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS

7.1.3 Recommended Plan and Current Status

The Working Group has considered and reviewed several options to provide additional transformation capacity in West Toronto area as part of the Central Toronto IRRP. Based upon the review, and consistent with the IRRP Working Group recommendation is to expand Runnymede TS by adding two 115/27.6 kV 50/83 MVA transformers and a 27.6kV switchyard with six feeders. This work is required to be completed as early as possible.

The Working Group also recommends that the Manby TS to Wiltshire TS tower line carrying circuits K1W/K3W/K11W/K12W be also upgraded at the same time. This option would maintain the load transfer capability between Leaside TS and the Manby TS under emergency or outage conditions in addition to supplying future load growth in the West Toronto Area.

The estimated total cost of the work is approximately $90 M, which includes $34 M for the station work at Runnymede TS, $16 M for the upgrade of four 9.5 km long circuits between Manby TS and Wiltshire TS and $40 M for distribution facilities by THESL. The transmission cost of $50M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals. The estimate is expected to be completed by the end of Q2 2016. It will also confirm if the targeted in-service date of May 2019 for this project is achievable. A Section 92 application will be submitted in 2016.

7.2 Southwest Toronto Area

7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS)

Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load demand in the southwest end of Toronto (see Figure 7-2). Based on the current RIP forecast the 400MW combined station capacity of the stations is forecast to be exceeded by summer 2020. Additional step down transformation is required to provide relief.

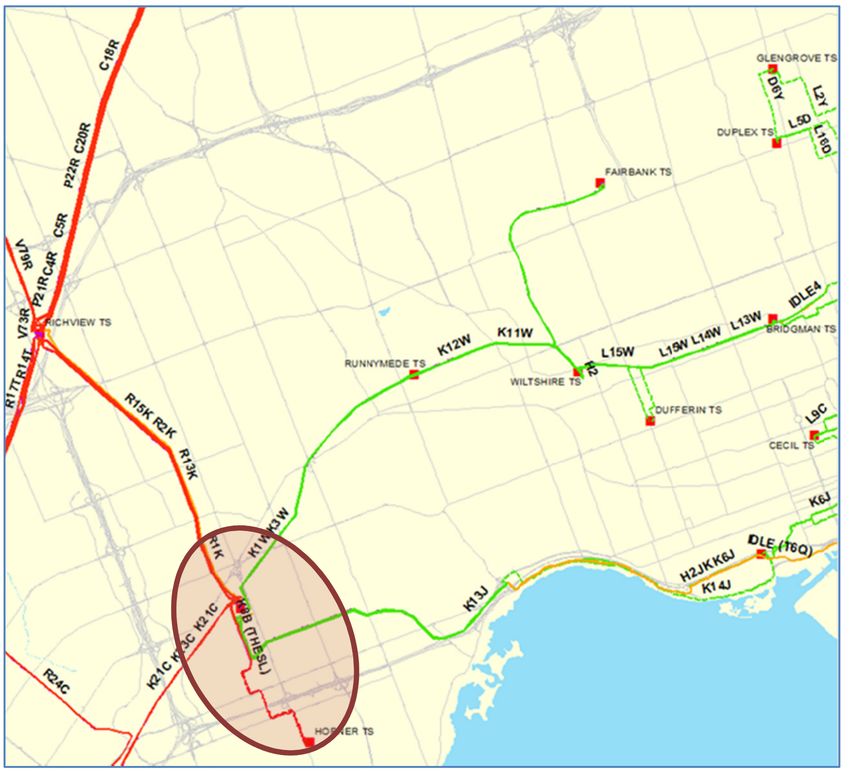

Figure 7-2 Horner TS and Manby TS Supply Area

7.2.2 Recommended Plan and Current Status.

To address the need for additional step down transformation capacity in the Southwest Toronto area, the Working Group's recommended building a second 230/27.6 kV DESN at the existing Horner TS site. Two 75/125MVA transformers will be installed at the station along with a new 27.6kV switchyard. Load transfer out of Manby TS to Horner TS is required to relieve Manby TS as the loading at that station exceeds its capacity. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL.

The estimated total cost of the work is about $53M, which includes $34 M for the station work at Horner TS and $19M for THESL distribution facilities. The transmission cost of $34M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals at the request of THESL. The current in-service date for the project is expected to be May 2020.

7.3 Downtown District

7.3.1 Station Capacity – JETC[2] Area

The Toronto Downtown Core area is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. John TS is connected to the Manby West system while Esplanade TS and Terauley TS are fed from the 115 kV Leaside / Hearn system. (see Figure 7-3)

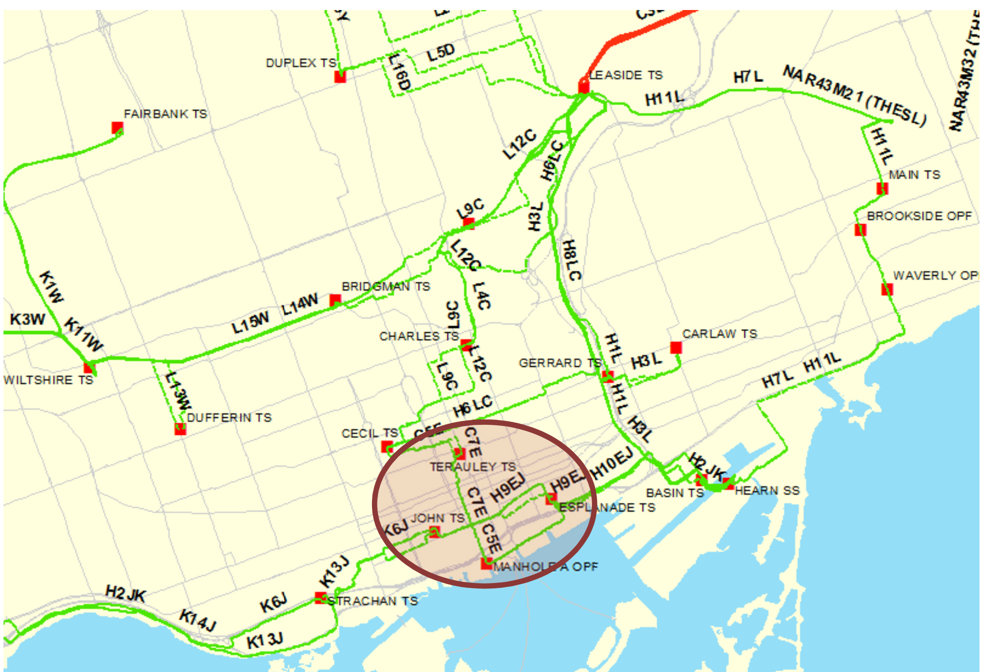

Figure 7-3 Toronto Downtown Supply Area

John TS was built in the 1950's and the THESL switchgear at the station is approaching end of life. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS in the Downtown

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[2] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

District near John TS with normal supplied from the 115 kV Manby West system. The station first phase capacity will be around 130 MVA and it is expected to be in service in 2016. Copeland MTS will provide a new source of supply to the area customers and facilitate the replacement of end of life switchgear at John TS.

With the new Copeland MTS in-service in 2016, adequate transformation capacity will be available in the Downtown District till 2027. However, most of this capacity will be at John TS as 13.8kV buses at both Terauley TS and Esplanade TS are at or approaching capacity limits. THESL anticipates that the need for new transformation facility is more advanced due to limited spare feeder positions available at John TS for new customer connection and load transfer required to facilitate the refurbishment work at John TS. At the current pace of development in these areas, both bus and feeder position in the Downtown Core area are expected to be at or near capacity within five to ten years[3]. Specific issues identified by THESL Hydro are as follows:

- By 2019 THESL forecasts that two busses will be overloaded (ie. loaded beyond 10 Day LTR) at George and Duke MS and two busses overloaded at John/Windsor TS.
- By 2025 THESL forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at John/Windsor TS.
- At John/Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- At George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- At Esplanade TS, there is only one bus with three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

7.3.2 Recommended Plan and Current Status

Based on the current information, the need to relieve the stations in Downtown District is expected to be beyond 2020. However, the need date may get delayed or brought forward if the load growth in this area is slower or faster than currently anticipated. The Working Group recommends that this need and timing should be further refined by THESL through their distribution planning process and included in updates to the IRRP and RIP. The uptake of CDM and DG should be preserved and re-assessed.

In the case where CDM and DG are deemed insufficient, building Copeland Phase 2 and installing additional transformers and two new buses at Copeland MTS site is the most cost effective way to meet the required THESL needs. The site and the high voltage switching facilities required to accommodate this expansion (Copeland Phase 2) are already included as part of the Copeland MTS Phase 1 project.Copeland MTS is an underground station and is not located adjacent to residential land uses. The THESL estimated cost for Copeland MTS Phase 2 to be approximately $46 M.

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[3] Further information may be found in THESL's rate application EB-2014-0116 to the Ontario Energy Board

7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor

7.4.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto Sub-Region. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. Along this Corridor there are two double circuit 230kV lines R1K/R2K and R13K/R15K. In addition the corridor contains an idle double circuit 115kV line. Figure 7-4 shows the area supplied by Richview TS x Manby TS circuits.

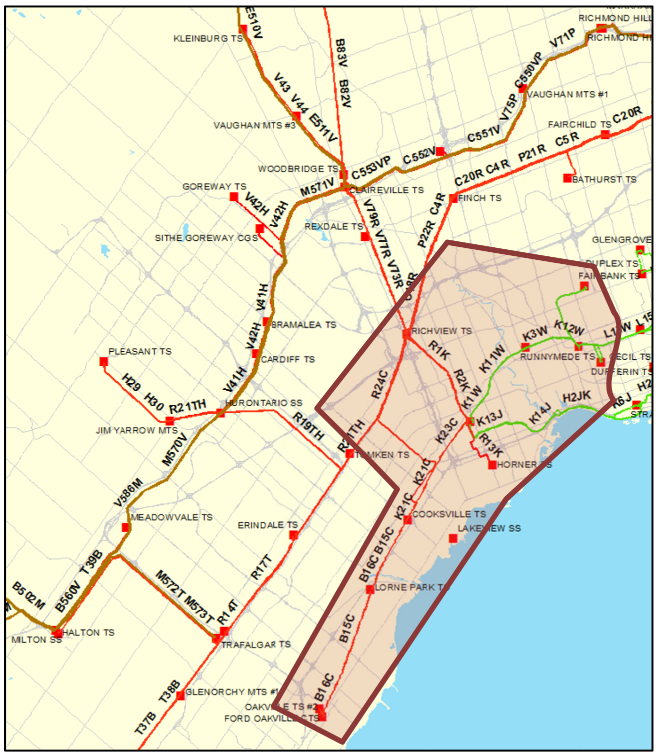


Figure 7-4 Richview x Manby Supply Area Map

The forecast loading on the Richview TS to Manby TS circuits is given in Table 7-2 below for both the high growth and low growth scenarios. The loads include the 115 kV Manby East, 115 kV Manby West, 230 kV Manby, and 230 kV Oakville-Cooksville loads. The need date for providing relief is 2020 for the high growth scenario and 2023 for the low growth scenario.

Table 7-2 also shows the effect of Metrolinx Mimico TPS on the need date for relief. In both scenarios, relief is required by 2020. The magnitude of Metrolinx load is large enough to trigger the reinforcement.

Again, due to the large incremental load from Mimico TPS, CDM will not be sufficient to help eliminate or even defer the need date for the transmission reinforcement. Transmission reinforcement is required to be implemented before the Mimico TPS can be connected.

Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area

	Limit	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
Base - Without Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1580**	1617	1646	1674	1698	1722	1742	1763
Low Growth	1540	1456	1481	1503	1530	**1544**	1557	1566	1572	1577	1597	1617
With Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1640**	1697	1726	1754	1778	1802	1822	1843
Low Growth	1540	1456	1481	1503	**1590**	1624	1637	1646	1652	1657	1677	1697

7.4.2 Alternatives Considered

The following alternatives are currently under consideration:

Upgrade four existing 230kV Richview TS x Manby TS circuits: Re-conductor with higher-capacity conductors on existing towers. Hydro One will check the feasibility of this option without major tower modifications and also in terms of outages arrangement. The estimated total cost of this option is about $16M, assuming that no major tower modifications and no bypass lines during re-conductoring are required.

Rebuild existing 115kV Richview TS x Manby TS line: Rebuild the existing idle 115 kV double-circuit line as a 230kV double-circuit line. The new 230 kV line is to share the existing terminations for circuits R2K and R15K at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits, effectively doubling the ampacity of R2K and R15K. This alternative requires the replacement of all the existing 115 kV towers with 230 kV towers. The estimated total cost of this option is about $19.5M.

Build two new 230 kV Richview TS x Manby TS circuits: Similar to the second alternative above, rebuild the two existing idle 115 kV double-circuit line as a 230kV double-circuit line. New terminations for these circuits are required at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits. This alternative not only provides higher transmission capacity but also increases the supply reliability to the Central Downtown and Southwest GTA area. The estimated total cost of this option is around $39.5M due to the extra station work required at the Richview TS and Manby TS.

Extend the Cooksville TS x Oakville TS line to Trafalgar TS: Extend the Cooksville TS x Oakville TS 230kV double circuit line B15C/B16C about 8km to Trafalgar TS where new 230kV switching facilties are also required. This alternative increases supply capacity and reliability to Southwest GTA area from Trafalgar TS, and thus alleviates the loading on the Richview x Manby corridor. The total estimated cost of this line and station work is around $54M.

CDM & DG: According to Central Toronto IRRP report, the potential DG development, targeted demand response and the potential incremental demand response in these areas supplied by Manby TS may defer the need for this transmission reinforcement by several years, depending on the load growth rate. However, with Mimico TPS connected near Horner TS, these targeted and potential incremental demand response will not be adequate due to the size of the extra load added by the TPS.

The Maintain Status Quo or Do Nothing alternative was not considered as it does not provide relief for the Richview x Manby transmission lines.

7.4.3 Recommended Plan and Current Status

The Metrolinx Mimico TPS information is new and was provided as part of the RIP after the IRRP was completed in April 2015. If this TPS is going to be in-service as planned in 2020, CDM initiatives will not effectively defer the need date for this transmission corridor because of the size of the additional load. Therefore, upgrading the existing Richview x Manby corridor or new supply path for the areas served by Manby TS will be required before the Metrolinx Mimico TPS can be connected.

The Trafalgar x Oakville line alternative, at $54M, is the highest cost alternative ($14.5M higher than the next most expensive alternative) and there is a risk that it may not be able to be completed in time to connect the the Metrolinx Mimico TPS in 2020. This alternative may also trigger the need for additional transformation facilities and thus would incur additional costs.

As a result, Working Group recommends that Hydro One proceed with the development and estimate work on the first three alternatives listed in Section 7.4.2 in 2016. Both EA and Section 92 approvals will be required and it is expected to take at least 3-4 years for the implementation of a wire solution. The Working Group will select the preferred alternative by December 2016. Hydro One will then plan to initiate project execution by summer 2018 in order to enable the connection of MetroLinx Mimico TPS by summer 2020.

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct)

C10A is a 20 km long radial circuit in Metro Toronto Northern Sub-Region from Cherrywood TS supplying Agincourt TS and Cavanagh MTS. The Metro Toronto Northern Sub-Region NA identified that the capacity of this circuit was thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. The flow on this section of the circuit might exceed its long-term emergency (LTE) rating under summer peak load conditions following certain contingencies.

A preliminary study based on the old field survey data was done in July 2015. The old record showed that the LTE rating was limited by some underbuilds along the line section. A new field survey was then carried out in October 2015. It was discovered that the aforementioned underbuilds had been previously removed, and the LTE rating of this line section should be 840A. The record is being updated. No further action is required.

7.6 Breaker Failure at Manby TS

7.6.1 Description

The failure of any of the Manby TS breakers A1H4 and H1H4 in the Manby West 230kV yard and the breaker H2H3 in the Manby east 230kV yard can cause the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS. This may result in the overload of the remaining autotransformer. Based on the Coincident RIP Forecast the need date for the work is summer 2018 and summer 2021 for Manby West and Manby East respectively.

7.6.2 Recommended Plan and Current Status

The Working Group has recommended that installation of a Special Protection Scheme (SPS) is the most cost effective means to mitigate the breaker failure risk.

Hydro One is working on the development and estimate work for the SPS at Manby TS. The preliminary estimate for this work is approximately $2M and this will be updated when the development work is complete by summer 2016. The planned in-service of this work is summer 2018.

7.7 Breaker Failure at Leaside TS

The failure of breaker L14L15 at Leaside TS can cause the outage of two of the Leaside TS to Bridgman TS circuits. This may result in the loss of Transformers T11, T12, T14 and T15 at Bridgman TS. Under this scenario, two of the four LV buses will be lost by configuration. Only transformer T13 remains in service and supplies buses HLA1 and HLA7.

The 15 minute LTR for the X and Y windings of Transformer T13 is 55MVA. Therefore, as long as the loading on the HLA1 and HLA7 does not exceed the 15 minutes LTR, the operator can take action to reduce load to within transformer LTE ratings.

A new normally open switch is being installed at Bridgman TS as part of the Leaside-Bridgman Transmission Reinforcement project. This new switch can be closed remotely following the loss of the circuit L15W to resupply the two Bridgman transformers from the circuit L13W. This will alleviate the loading of the transformer T13 and the circuit L18W. and any possible voltage issue at Bridgman TS. Therefore, no investment is recommended.

7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies

Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS (CxL) can result in the loss of two of the three 230/115kV autotransformers on the same half of Leaside TS. The long-term emergency rating of the remaining autotransformer may be exceeded if only a single combustion unit at the Portland Energy Centre (PEC) is available, coincident with either of the abovementioned double contingencies during peak load condition.

The Working Group recommends that no further work is required in the near- and mid-term as there is already an existing operating instruction in place to cover the overload issue of the remaining Leaside autotransformer by closing the 115kV bus-tie at Leaside TS.

7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)

Bathurst TS, Fairchild TS, and Leslie TS are supplied by the 230 kV Richview x Cherrywood x Parkway system in the Metro Toronto Northern Sub-Region. Following two circuit contingencies, approximately 240-300 MW of load during summer peak time could be lost during each contingency scenario, as follows:

Table 7-3 Maximum Load Loss during Two Circuit Contingencies

Double Element Contingency	Station Connected	Non-Coincident Load Forecast (MW)	
		2015	2025
P22R + C18R	Bathurst TS	271	279
C18R + C20R	Fairchild TS	292	301
P21R + C5R	Leslie TS	239	249

There are currently no existing transmission switching facilities to allow load restoration immediately. Partial load could be restored via distribution transfer to the nearby stations.

For Bathurst and Leslie cases, the stations are supplied by circuits on separate transmission lines for all or most sections. The probability of occurrence of overlapping outages on circuits on different tower lines is extremely low. The supplied circuits for Fairchild TS are on common tower for two-third of the line (approximately 32km).

Based on the outage records in the past 25 years there has been no incidence of any double contingencies described above.

A single transformer station would require four motorized disconnect switches to be useful. Typical cost for installing these transmission switching facilities per station would be between $8-10M.

Based on the low probability of frequency of such events versus the high mitigation cost, the Working Group recommendation is that no further action is required.

7.10 Long Term Needs

Four longer term needs had been identified in the Central Toronto IRRP as follows:

- Transmission Line Capacity – 115 kV Manby West To Riverside Junction
- Transformation Capacity – 230/115 kV Manby TS
- Transformation Capacity – 230/115 kV Leaside TS
- Leaside TS x Wiltshire TS 115kV circuits

Loading on Manby TS and the Manby TS x Riverside Junction circuit are within ratings over the study period under the Coincident RIP forecast. The Working Group recommendation is that no further action is required.

The Leaside TS transformer and the Leaside TS x Wiltshire circuits will require relief in the long term. This issue will be considered in the next planning cycle. The Working Group recommendation is that no further action is required. However, Hydro One and IESO will continue to monitor loads and initiate necessary relief measures, if required.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE METRO TORONTO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Supply Security – Breaker Failure at Manby West & East TS
II	West Toronto Area - Station Capacity and Line Capacity
III	Southwest Toronto - Station Capacity
IV	Downtown District - Station Capacity
V	230 kV Richview x Manby Corridor– Line Capacity
VI	Leaside Autotransformers
VII	Line Capacity – 115 kV Leaside x Wiltshire Corridor

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near-term and mid-term needs are summarized in the Table 8-2 below. Investments to address the long-term needs where there is time to make a decision (Need No. VI & VII), will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Est. Cost	Needs Mitigated
1	Manby SPS	Transmitter to carry out the work	Hydro One	2018	$2M	I
2	Runnymede Expansion & 115 kV Manby x Wiltshire Corridor Upgrade	Transmitter to carry out the work	Hydro One	2019	$90M	II
3	Horner Expansion	Transmitter to carry out the work	Hydro One	2020	$53M	III
4	230 kV Richview x Manby Corridor Upgrade	Transmitter to carry out the work	Hydro One	2020	$20-40M	V
5	Copeland Phase 2	LDC to carry out work & monitor growth	THESL	2020+	$46M	IV

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered every five years. The next planning cycle for the Metro Toronto Region is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Central Toronto Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/2015-Central-Toronto-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Metro Toronto Region – Northern Sub-Region", 11 June 2014.
http://www.hydroone.com/RegionalPlanning/Toronto/Documents/Needs%20Assessment%20Report%20-%20Metro%20Toronto%20-%20Northern%20Subregion.pdf

Appendix A. Stations in the Metro Toronto Region

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15W/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15W
Dufferin TS T2/T4	115/13.8	L13W/L15W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

Appendix B. Transmission Lines in the Metro Toronto Region

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	H9EJ, H10EJ	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix C. Distributors in the Metro Toronto Region

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS (Future)	Tx

Distributor Name	**Station Name**	**Connection Type**
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
	Warden TS	Tx
PowerStream Inc.	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
Veridian Connections Inc.	Malvern TS	Dx
	Sheppard TS	Dx
Enersource Hydro Mississauga Inc.	Richview TS	Dx

Appendix D. Metro Toronto Regional Load Forecast (2015-2035)

Table D-1 Non-Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	57	60	64	67	68	69	70	71	73	75	77	79	81	83
		Bridgman	179	174	177	179	181	182	183	184	185	187	189	191	193	195	198
		Carlaw	131	65	66	68	70	71	73	74	72	71	72	75	78	80	82
		Cecil	204	168	169	171	173	175	177	178	181	183	186	190	193	196	199
		Charles	200	151	153	156	158	159	161	162	165	167	170	172	173	177	181
		Dufferin	161	141	144	147	149	150	150	150	152	154	156	158	159	161	163
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	196	201	206	210	215
		Gerrard	62	44	45	46	48	49	50	51	63	78	88	90	92	93	94
		Glengrove	84	55	57	58	59	60	60	61	62	63	64	66	67	68	69
		Main	72	65	64	63	62	63	64	66	65	65	66	69	72	75	77
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	67	68	69	70	70	71	72	72	72	72	73	74	75	76
	ManbyE115-27.6	Runnymede	109	116	118	120	122	122	123	123	125	126	128	129	131	132	133
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	175	178	181	184	186	187	188	190	193	195	197	199	201	203
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	276	276	189	189	192	195	198	202	206	209	213	218	221	225
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2143	2175	2206	2255	2279	2303	2341	2390	2444	2495	2540	2587	2626	2666
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	169	171	173	175	175	175	175	176	177	178	180	181	182	183
		Leaside	210	156	158	159	161	161	161	161	163	165	166	168	170	172	174
		Scarboro	340	222	225	227	230	230	230	230	231	233	234	236	238	239	241
		Sheppard	204	170	170	171	171	171	171	171	173	174	175	176	178	179	180
		Warden	183	126	128	129	130	130	130	130	131	132	133	134	135	136	137
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1037	1047	1057	1067	1067	1107	1127	1155	1164	1172	1180	1189	1197	1206
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	271	272	274	275	275	275	275	277	279	281	283	285	287	289
		Cavanagh	157	141	141	141	142	142	142	142	143	144	145	146	147	148	149
		Fairchild	357	292	293	295	297	297	297	297	299	301	303	306	308	310	312
		Finch	363	289	292	295	298	298	298	298	300	302	304	306	309	311	313
		Leslie	325	239	241	244	246	246	246	246	248	249	251	253	255	256	258
		Malvern	176	106	106	107	107	107	107	107	108	109	109	110	111	112	113
Northern 230kV Total			1885	1433	1444	1455	1466	1467	1468	1469	1479	1490	1500	1511	1521	1532	1543
Western 230kV	Manby230	Horner	179	144	146	148	150	151	152	153	155	157	157	156	155	157	159
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	135	135	135	135	134	133	132	133	134	135	136	137	138	139
		Richview T1T2EZ	154	130	131	131	131	130	129	128	129	130	131	132	133	134	135
		Richview T5T6JQ	188	109	110	110	110	109	108	108	108	109	110	111	111	112	113
		Richview T7T8BY	113	54	54	54	54	54	54	53	54	54	54	55	55	56	56
Western 230kV Total			1042	805	811	818	825	825	905	945	994	1003	1013	1023	1034	1043	1052
Grand Total			6995	5419	5477	5537	5613	5638	5783	5883	6019	6100	6180	6254	6331	6398	6466

Table D-2 Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	52	55	58	61	62	63	63	65	66	68	70	72	73	75
		Bridgman	179	171	173	175	177	179	180	181	182	183	185	187	189	192	194
		Carlaw	131	61	63	65	67	68	69	70	69	68	68	71	74	76	78
		Cecil	204	152	154	156	158	159	161	162	165	167	170	173	176	178	181
		Charles	200	150	152	155	157	159	160	161	164	166	169	171	172	176	180
		Dufferin	161	139	142	144	147	147	148	148	150	152	153	155	157	159	160
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	195	200	206	210	215
		Gerrard	62	44	45	46	47	48	49	50	62	77	87	89	91	92	93
		Glengrove	84	52	53	55	56	57	57	58	59	60	61	62	64	64	65
		Main	72	59	59	58	57	58	59	60	60	60	61	64	67	69	71
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	61	61	62	63	64	64	65	65	65	65	66	67	68	69
	ManbyE115-27.6	Runnymede	109	96	98	99	101	101	102	102	103	105	106	107	109	110	110
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	174	177	179	183	184	185	186	188	191	193	195	197	199	201
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	267	266	179	179	182	185	188	191	195	199	202	206	210	213
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2067	2097	2128	2176	2198	2222	2259	2307	2359	2409	2453	2498	2536	2575
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	154	155	157	159	159	159	159	160	161	162	163	164	166	167
		Leaside	210	154	156	158	159	159	159	159	161	163	165	167	168	170	172
		Scarboro	340	220	222	225	227	227	227	227	229	230	232	234	235	237	239
		Sheppard	204	164	164	165	165	165	165	165	166	168	169	170	171	172	174
		Warden	183	125	126	127	129	129	129	129	130	130	131	132	133	134	135
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1010	1020	1030	1040	1040	1080	1100	1128	1136	1144	1152	1160	1168	1176
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	245	247	248	249	249	249	249	251	253	255	257	258	260	262
		Cavanagh	157	119	119	119	120	120	120	120	120	121	122	123	124	125	126
		Fairchild	357	256	257	259	260	260	260	260	262	264	266	268	270	272	273
		Finch	363	273	276	278	281	281	281	281	283	285	287	289	291	293	295
		Leslie	325	223	225	227	229	229	229	229	231	233	234	236	238	239	241
		Malvern	176	106	106	106	107	107	107	107	108	108	109	110	111	111	112
Northern 230kV Total			1885	1317	1327	1337	1347	1348	1349	1351	1360	1370	1379	1389	1399	1408	1418
Western 230kV	Manby230	Horner	179	129	131	133	135	136	137	138	140	141	142	141	139	141	143
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	133	133	133	133	132	131	130	131	132	133	134	135	136	137
		Richview T1T2EZ	154	128	128	129	129	128	127	126	127	128	129	130	131	131	132
		Richview T5T6JQ	188	107	107	108	108	107	106	106	106	107	108	109	109	110	111
		Richview T7T8BY	113	52	52	52	52	52	51	51	51	52	52	53	53	53	54
Western 230kV Total			1042	782	788	794	801	801	881	921	970	979	988	998	1009	1018	1027
Grand Total			6995	5176	5232	5289	5363	5388	5532	5631	5765	5843	5920	5992	6066	6131	6196

Appendix E. List of Acronyms

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

Filed: 2015-05-31
EB-2016-0160
Exhibit B1-02-03
Attachment 8
Page 1 of 202

NORTH OF DRYDEN INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | January 27, 2015

ieso
Independent Electricity System Operator

Explanatory Note Regarding January 1, 2015 OPA-IESO Merger

On January 1, 2015, the Ontario Power Authority (OPA) merged with the Independent Electricity System Operator (IESO) to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

This report was largely completed prior to January 1, 2015. Any mention of the activities performed by the former OPA or the former IESO in this report refers collectively to the new IESO.

*Administrative change on April 1, 2015, page 22 , to correct timeframe of the Conservation First Framework Directive.

Contents

Table of Figures

Summary of Plan Highlights

- Drivers for increased electricity demand in the areas surrounding Red Lake, Pickle Lake and Ring of Fire include *connecting remote First Nation communities and growth in the mining sector*.

- The OPA recommends a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake and upgrades to existing lines between Dryden and Red Lake for immediate implementation to address near- and medium- term needs for the Pickle Lake and Red Lake areas.

- Incremental longer term solutions to supply Ring of Fire and Red Lake are not required at this time. Longer term options will be re-evaluated in the next planning cycle (1-5 years).

- Options to supply the Ring of Fire include transmission utilizing an East-West or North South corridor, or on-site generation. East-West and North-South transmission options are comparable in cost under the high demand scenario and the potential need for a transmission line should be considered in the planning of a common infrastructure corridor to the Ring of Fire.

- Long-term options for the Red Lake area include local gas generation or new transmission.

Summary of Updates from August 2013 draft IRRP

- Revised demand forecast used different methodology, includes updated data and is represented by three scenarios – reference, high and low; August 2013 draft included high and low scenarios, but did not include a reference scenario.
- Revised demand forecast indicates relatively higher forecasted demand in the Pickle Lake subsystem, and relatively lower forecasted demand in the Red Lake subsystem than in the August 2013 draft.
- Recommendation is for new 230 kV line to Pickle Lake in this version; voltage recommendation was not specified in the August 2013 draft.
- Recommended line upgrades from Dryden to Red Lake are expected to be sufficient to the end of the planning period for the reference and low forecast scenarios, and to 2030 for the high forecast scenario. The August 2013 draft indicated that the upgrades may be insufficient in the medium-term for the high scenario.
- Recommendation to discuss reactive services of Manitou Falls GS with OPG, as per OPG's written submission.
- Revised economic analysis methodology – refer to Appendices 10.6, 10.7, and 10.8 for details.

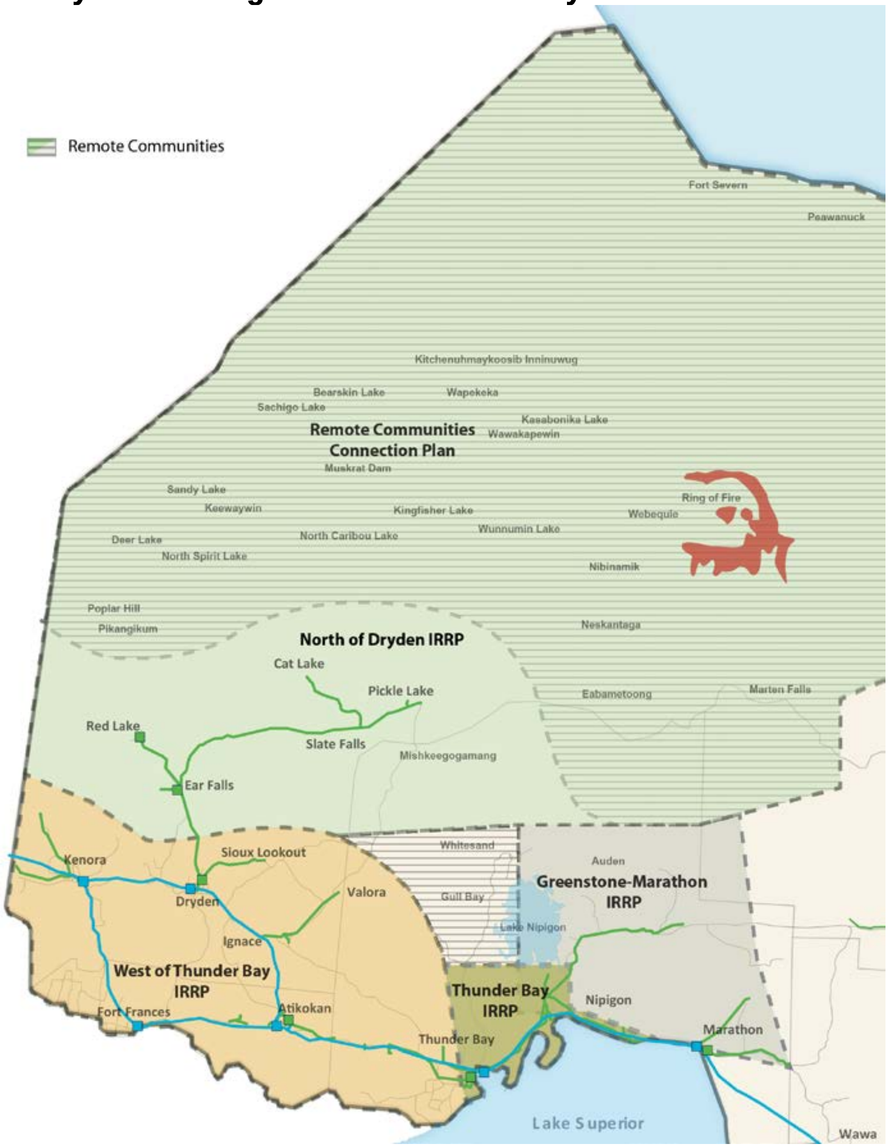
1 EXECUTIVE SUMMARY

Context and Purpose

The purpose of the North of Dryden Integrated Regional Resource Plan ("regional plan", "North of Dryden IRRP", or "IRRP") is to identify the near-term and medium- to long-term electricity supply needs of the area and assess options that are available to address the needs in a timely, reliable and cost-effective manner. The IRRP is intended to provide the overall planning context to address regional supply adequacy and reliability needs.

The North of Dryden IRRP is one of several electricity planning initiatives that the the Ontario Power Authority ("OPA") is undertaking for the Northwest Ontario region. Figure 1 identifies the IRRP initiatives currently being undertaken by OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region. This includes requirements at Pickle Lake and Red Lake related to the connection of the 21 remote First Nation communities ("remote communities") that are economic to connect, as outlined in the Remote Community Connection Plan as well as new mining developments forecasted in the area. It also coordinates with the West of Thunder Bay IRRP, ensuring that the West of Thunder Bay transmission system is able to accommodate the expected growth north of Dryden. The North of Dryden IRRP will also coordinate options related to supply to the Ring of Fire with the Greenstone-Marathon IRRP.

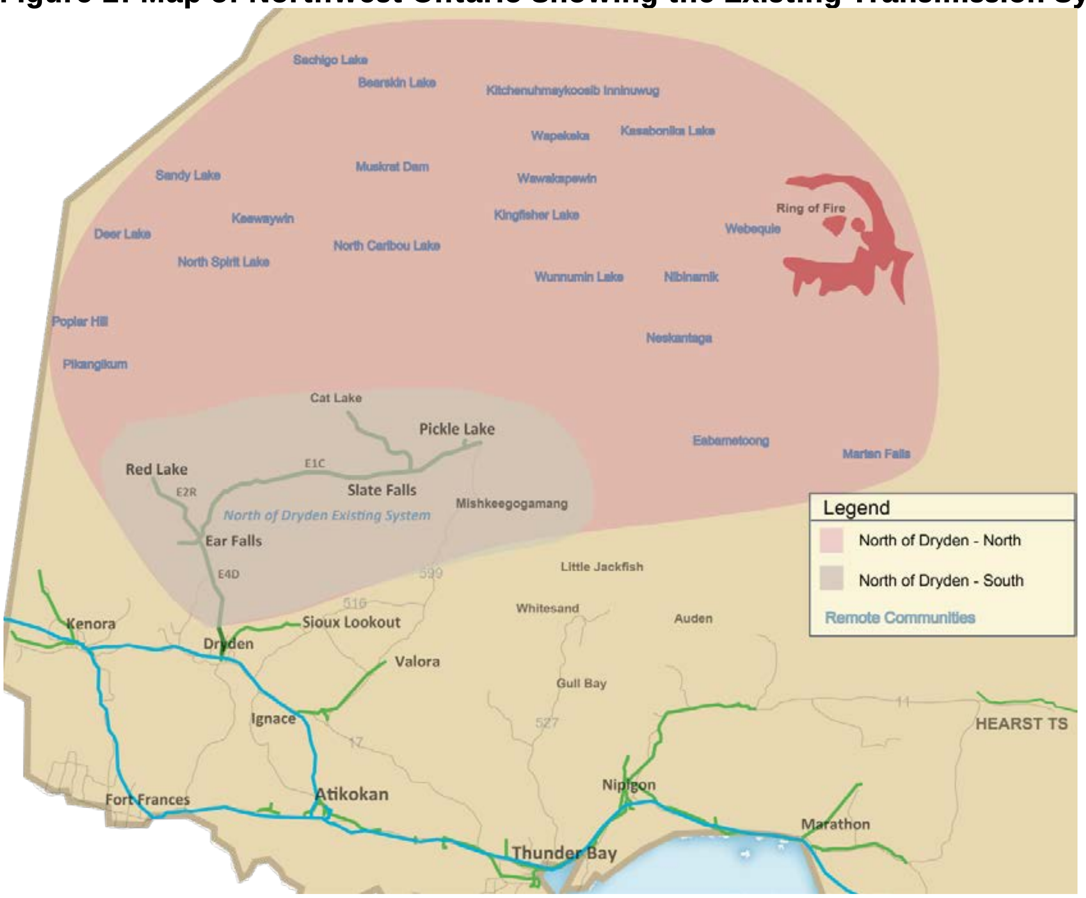
Figure 1: Summary of Planning Initiatives Underway in Northwest Ontario



The North of Dryden sub-region is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario (“MNO”). The southern portion of the sub-region (shown in Figure 2) is currently served by Ontario’s transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest and Pickle Lake to the northeast. Existing mining activity is primarily located in this southern portion of the North of Dryden sub-region and is largely focused around the towns of Ear Falls, Red Lake and Pickle Lake. The northern portion of the North of Dryden sub-region (shown in Figure 2) contains the

21 remote First Nation communities which are economic to connect, one operating mine, and the mine development area known as the Ring of Fire. At present, only one mine north of Pickle Lake is connected to the transmission grid through a privately owned transmission line.

Figure 2: Map of Northwest Ontario Showing the Existing Transmission System



The North of Dryden sub-region is forecast to experience some of the highest growth in electrical demand in Ontario. Currently the electricity transmission system serving the area is at capacity and is unable to accommodate demand growth.

Mining sector expansion is the primary driver of electricity demand growth in the area; through the expansion of existing mines and the development of new mines, as well as growth in the industries and communities that support the mining sector. Remote communities in the North of Dryden sub-region are currently supplied by diesel generation, however the draft Remote Community Connection Plan[1] developed jointly by the remote communities and the OPA indicates that there is an economic case for connecting the majority of these communities to Ontario's transmission system. The Remote Community Connection Plan is the OPA's primary planning document for these communities, however, the connection would put additional demand requirements on the local transmission system in the areas of Red Lake and Pickle Lake, which is considered in this IRRP.

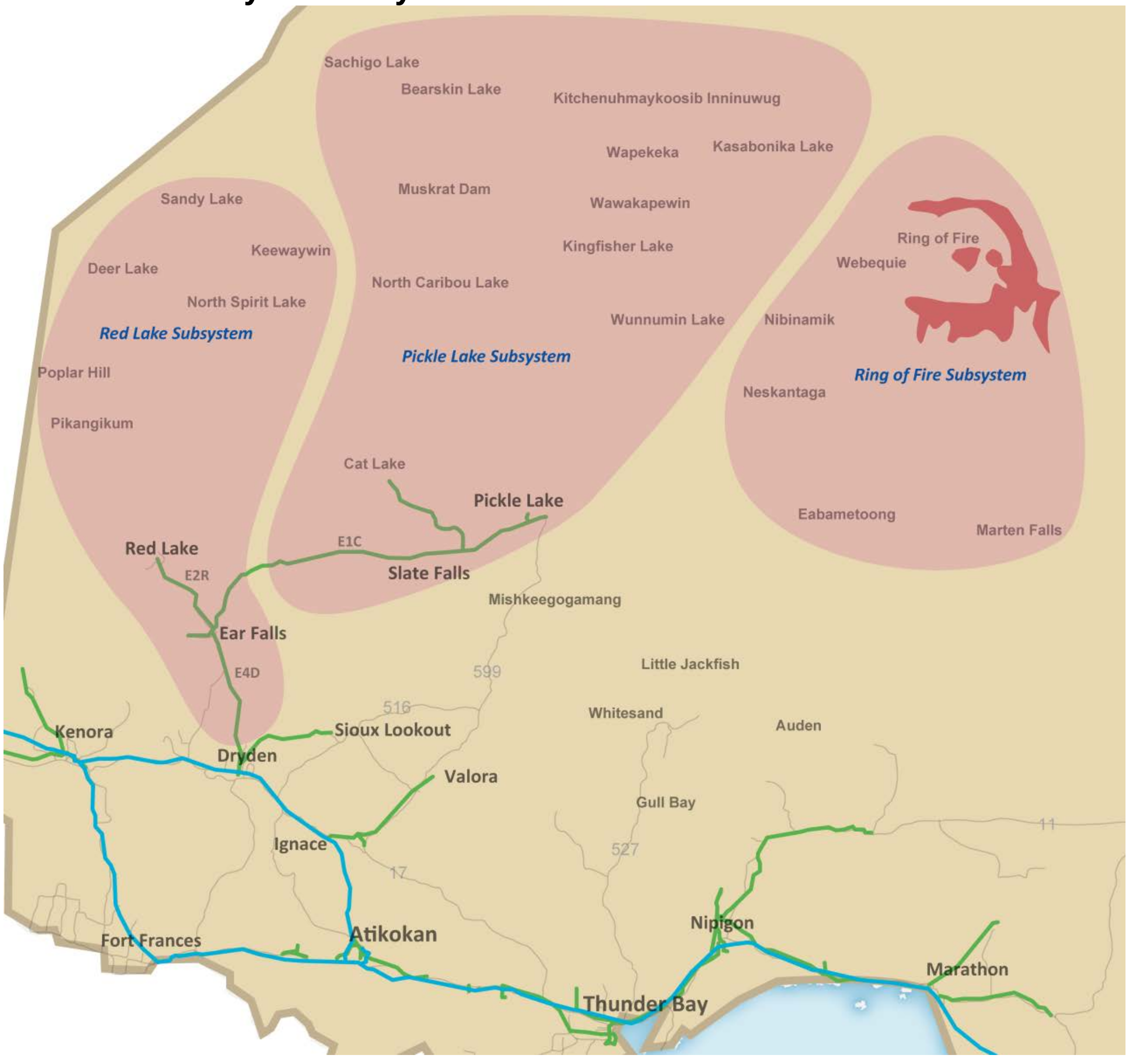
Need Identification

Over the past decade, the annual electricity demand growth in the North of Dryden sub-region has averaged about 1.9%. Growth plans of existing and future customers that are expected to be supplied from the local transmission system indicate that there will be a significant increase in electricity demand over the next 20 or more years.

For study purposes, the area has been segmented into three subsystems generally surrounding Red Lake, Pickle Lake and the Ring of Fire.

[1] A report entitled "Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario" was developed by the Northwest Ontario First Nations Transmission Planning Committee and the OPA. The document can be found at this website: http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

Figure 3: North of Dryden Subsystems



Where growth in electricity demand identified in these subsystems cannot be met by the existing system, technically feasible conservation, local generation, and transmission options are identified and compared based on their ability to cost effectively meet the needs.

The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information available at the time.

This regional plan has identified that there is a near-term (2014 to 2018) need for additional Load Meeting Capability[2] ("LMC") in the transmission system currently serving the Red Lake and Pickle Lake subsystems. The regional plan has also identified that the majority of the forecasted growth is expected to occur during the medium term between 2019 and 2023. This is the period when remote communities and new mines are expected to develop and connect to the transmission system. The long term is characterized by steadily increasing demand over the remainder of the planning period (to 2033). The need for incremental LMC by subsystem is summarized in Table 1 below.

Table 1: Incremental Capacity Needs by Subsystem

Sub-system	**Near-term Capacity Needs (Present to 2018 in MW)**			**Medium-term Capacity Needs (2019-2023 in MW)**			**Long-term Capacity Needs (2024-2033 in MW)**		
	High	Reference	Low	High	Reference	Low	High	Reference	Low
Pickle Lake	20	18	15	36	28	17	59	47	11
Red Lake	30	30	30	62	44	36	75	48	39
Ring of Fire	22	22	4	67	27	5	73	29	7

Given the magnitude of the increase in electrical demand associated with expanding an existing mine or opening a new mine, as well as growth in electricity demand from growing communities, the area is currently deficient in supply capacity and is expected to become increasingly deficient over the near, medium, and long term.

Options Analysis

The technically feasible options available to meet needs in the Red Lake, Pickle Lake and Ring of Fire subsystems and their implementation timing are outlined in Table 2 below. All costs are net present cost in 2014 dollars, unless stated otherwise (a detailed description of costing methodology can be found in Appendices 10.6, 10.7, and 10.8):

[2] Existing system is thermally limited.

Table 2: Summary of Options

Implementation Timing	Pickle Lake Subsystem	Red Lake Subsystem	Ring of Fire Subsystem
	Conservation and DG Options		
Near term and medium to long term (2014-2033)	Customers may investigate opportunities for additional conservation beyond targets and DG resources to suit their own electrical requirements; Industrial Accelerator Program ("IAP"), Aboriginal Conservation Program, Aboriginal Community Energy Plans Program, remote renewable opportunities after grid expanded to supply remote First Nation communities.		
	Transmission Options		
Near term (2014-2018)	Build a new 115 kV OR 230 kV transmission line from the Dryden/Ignace area to Pickle Lake **Cost: $80 M - $114 M**	Upgrade existing transmission lines serving Red Lake (E4D and E2R) **Cost: $11 M**	East-West Corridor Option: Build a new 115 kV transmission line from Pickle Lake to Ring of Fire for demand up to 67 MW, or build a new 230 kV line if greater than 67 MW. **Cost: $106 M - $156 M** OR North-South Corridor Option: Build a new 230 kV transmission line from either Marathon or a point east of Nipigon to Ring of Fire **Cost: $175 M**
Medium to long term (2019-2033)		If load in the Red Lake subsystem exceeds 109 MW: Install additional voltage support **Cost: $1 M** If load in the Red Lake subsystem exceeds 130 MW: Build a new 115 kV or 230 kV transmission line between Dryden and Ear Falls **Capital Cost: $91 M - $132 M**[3]	
	Generation Options		
Near term (2014-2018)	Gas-fired generator at Pickle Lake fuelled by compressed natural gas, sized and expanded to meet demand growth of up to 31 MW in medium term and up to 76 MW in long	Gas fired generator utilizing up to 30 MW of available gas pipeline capacity at Red Lake **Cost: $51 M**	On-site generation fuelled by compressed natural gas or diesel, **Cost: $209 M - $946 M**[4] Separately connect remote communities
Medium to long term (2019-2033)		Gas-fired generator utilizing up to 30 MW of available gas pipeline	

[3] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of transmission in the long term is $10-15 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[4] Range indicates variation in cost of diesel and compressed natural gas as well as sizing of the generation facility to accommodate the low, reference or high forecast scenarios.

	term **Cost: $158 M - $317 M**	capacity at Red Lake, followed by additional 30 MW at Ear Falls if a new gas pipeline is built **Capital Cost: $95 M - $ 153 M**[5]	**Cost: $ 62 M** **Total Cost: $ 272 M - $1,009 M**

This regional plan considers overall societal costs[6] in determining the least-cost options for supplying the study area. The analysis in this regional plan does not consider the allocation of costs that are attributable to individual customers in the area or how this may affect individual customer decisions on pursuing the societal least-cost options. The final determination of cost allocation between parties will be made through the applicable regulatory process and/or through commercial agreements. For example, cost allocation of transmission and distribution infrastructure is made by the Ontario Energy Board ("OEB"), benefitting customers, and/or transmitters and distributors in the area in accordance with rules set out in the Transmission System Code ("TSC") and Distribution System Code ("DSC").

Summary of Aboriginal, Stakeholder, and Public Feedback

Aboriginal Consultation

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on

[5] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of generation in the long term is $6-8 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[6] Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment, operations and maintenance, fuel, etc.) but excludes the cost of land, taxes and potential impact benefit agreements that may be reached with affected First Nations, which proponents may be required to pay. Governments (and their agencies) undertake projects of infrastructural, environmental or health and safety enhancements in the wider public interest, assessing project merits in terms of the long-term return to current and future generations of society as a whole, using a social discount rate ("SDR"). The OPA uses a four-percent SDR to determine the present value of options over the planning period.

the Draft North of Dryden IRRP. The OPA and Ministry of Energy provided written notice to each community. The OPA also followed up by telephone to each community and sent all presentation material to each community in advance of the sessions.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. The OPA met with Red Sky Métis Independent Nation on June 19, 2014 at Red Sky's office in Thunder Bay.

The OPA was in contact with the Métis Nation of Ontario ("MNO") on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO's member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights.

Municipal Engagement

The OPA met with municipal representatives in person to solicit feedback on the Draft North of Dryden IRRP to be incorporated into the North of Dryden IRRP. The OPA met with municipal representatives from Pickle Lake, Greenstone, Red Lake, Sioux Lookout, Marathon, Dryden and Ignace in December 2013 and February 2014.

Following the municipal engagement meetings, several common themes emerged from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

Written Feedback

Since the posting of the Draft North of Dryden IRRP, the OPA has received written feedback and has followed up with those who contributed written submissions. Written feedback was submitted from the Common Voice Northwest Energy Task Force

("CVNW"), the township of Pickle Lake, Imperium Energy on behalf of the municipality of Greenstone, the Ontario Waterpower Association, Ontario Power Generation ("OPG"), Gold Canyon Resources Inc., Energy Acuity, and an independently represented stakeholder.

In general, written submissions asked clarifying questions regarding the content in the draft report. It should be noted that CVNW submitted a 51-page report of comment covering topics across the entire Northwest. The OPA has considered the input in this report, has met with CVNW since publishing the draft report, and will continue to consider their feedback for regional planning initiatives across northwestern Ontario.

Based on written feedback provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, OPG identified that Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls Switching Station ("SS") associated with the installation of voltage control devices. The OPA has considered this feedback in finalizing the plan.

Webinar

The first draft of the North of Dryden IRRP was posted to the OPA's website in August 2013 and a webinar was held on November 21, 2013 to present the draft IRRP and solicit feedback. Main points of feedback were consistent with that received in written submissions and engagement and consultation meetings.

Recommended Solutions/Actions to be initiated in the near term

The OPA recommends the following solutions for implementation as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem), installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control

devices at Pickle Lake, and transferring the existing load on the line between Ear Falls and Pickle Lake (E1C) to be supplied by this new line;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. Having the Independent Electricity System Operator ("IESO")/OPA initiate discussions with OPG for new reactive power services provided by Manitou Falls Generating Station ("GS") if it is confirmed to be beneficial to the ratepayer.

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long-term forecast scenarios.

The estimated combined present value cost of recommendations (1) and (2) during the planning period is about $124 million[7]. Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

The OPA understands that near-term actions for implementing a new line to Pickle Lake have been initiated by two proponents. Additionally, the OPA understands that Hydro One and various customers in the Red Lake area have initiated discussions to implement the upgrades from Dryden to Red Lake. Implementation of the new 230 kV line to Pickle Lake and the 115 kV line upgrades from Dryden to Red Lake continue to be supported by the OPA.

[7] The August 2013 draft identified this cost as $234-271 million. This change in cost is due to a change in methodology for the NPV economic analysis – treating avoided system generation as a benefit of generation options, rather than a cost to transmission options (as in the 2013 draft). NPV economic analysis is an analysis tool to compare costs over a time horizon, and is not the same as the total project cost for the option being investigated.

Options for the medium to long term period

Pickle Lake Subsystem

The recommendation to build a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake in the near term would be sufficient under all forecast scenarios for the medium to long term.

Red Lake Subsystem

Following the completion of the near-term recommendations, the 130 MW LMC is expected to be sufficient beyond the planning period for the low and reference forecast scenarios, and until 2030 for the high scenario as shown in Table 1. Therefore, the near-term recommendations are expected to be sufficient to meet the needs of the Red Lake subsystem for the long term.

As shown in Table 2, two options have been investigated for the Red Lake subsystem to address any forecasted load in excess of 130 MW. The OPA recommends that these options, incremental natural gas-fired generation at Red Lake and a new transmission line, be retained as viable long term options and re-evaluated in the next planning cycle (1-5 years) for this IRRP. Re-evaluating plans up to every 5 years is consistent with OEB requirements in the TSC, DSC and the OPA license.

Ring of Fire Subsystem

There are several options for supplying the Ring of Fire subsystem depending on the load growth scenario. The analysis indicates that the Ring of Fire subsystem can be cost-effectively served by a 115 kV transmission connection from Pickle Lake (serving five remote communities and mines at the Ring of Fire), if demand over the long term is 67 MW or less. If demand is reasonably certain to exceed 67 MW in the subsystem, a 230 kV transmission line utilizing an East-West corridor from Pickle Lake, or a 230 kV transmission line utilizing a North-South corridor from either Marathon or east of Lake Nipigon would be required, where these alternatives have approximately equal cost.

The 230 kV transmission options are also expected to be more cost-effective from a societal perspective than the combined cost of developing local generation to serve the total mining load and separately connecting remote communities to Pickle Lake.

The OPA is aware of ongoing work for infrastructure development for the Ring of Fire. Common infrastructure corridors serving multiple uses provide synergies for cost and environmental approvals, and may reduce environmental impacts. The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

Conservation Options

Recently, the OPA has received new direction[8] from the Minister of Energy pertaining to the framework for conservation programs moving forward. Directives from the Minister of Energy set conservation targets, which Local Distribution Companies ("LDC") will plan to meet through the development of conservation plans and programs for their service area. The spirit of this new direction is to provide more opportunity for LDCs, communities, and industry to participate in conservation initiatives so a broader scope of programs is expected to be tailored to the local needs of the region. For remote communities, conservation opportunities are considered in the Remote Community Connection Plan.

Furthermore, the following programs are available through the OPA to Aboriginal Communities:

- Aboriginal Conservation Program, with the aim to provide customized conservation services designed to help First Nation communities, including remote and northern communities, reduce their electricity use in residential housing, and in commercial and institutional buildings, like stores, schools and

[8] *2015-2020 Conservation First Framework (March 31, 2014), Continuance of the OPA's Demand Response Program under IESO management (March 31, 2014), and Industrial Accelerator Program (July 25, 2014).*

band offices. This program will be offered for one additional year (ending December 31, 2015) until such time as LDCs are able to develop a CDM program which recognizes the specific requirements of on-reserve First Nation communities as per the 2015-2020 Conservation First Framework Directive.

- Aboriginal Community Energy Plans program to support Aboriginal participation in Ontario's energy sector by providing up to $90,000 per community in funding to First Nation or Métis communities for local energy planning activities, with remote communities being eligible for an additional $5,000.

Electricity demand of the industrial sector is quite significant in this area. The Industrial Accelerator Program ("IAP") is available to industrial customers as a means of achieving conservation savings with financial assistance from the OPA.

Given the large component of industrial demand and number of First Nation and Métis communities in the area, the above mentioned programs should be pursued.

Generation Options for the Medium- to Long-term Period

On May 30, 2014, the OPA closed submissions for the Northwest Ontario Request for Information ("NW RFI"). The purpose of the NW RFI was to gather information on the potential availability of diverse resource options in northwestern Ontario, with particular focus on the interim period to 2020. As part of the NW RFI, the OPA received submissions totaling over 4000 MW for the entire Northwest region. Of the over 4000 MW, a few potential projects were identified in the North of Dryden sub-region and were consistent with the generation options investigated as part of this IRRP.

Procurement of generation is not recommended to be pursued at this time for meeting needs in the North of Dryden sub-region. However, if a generation solution is required for other areas of the Northwest, local benefits of these options to the North of Dryden sub-region will be re-evaluated.

2 INTRODUCTION

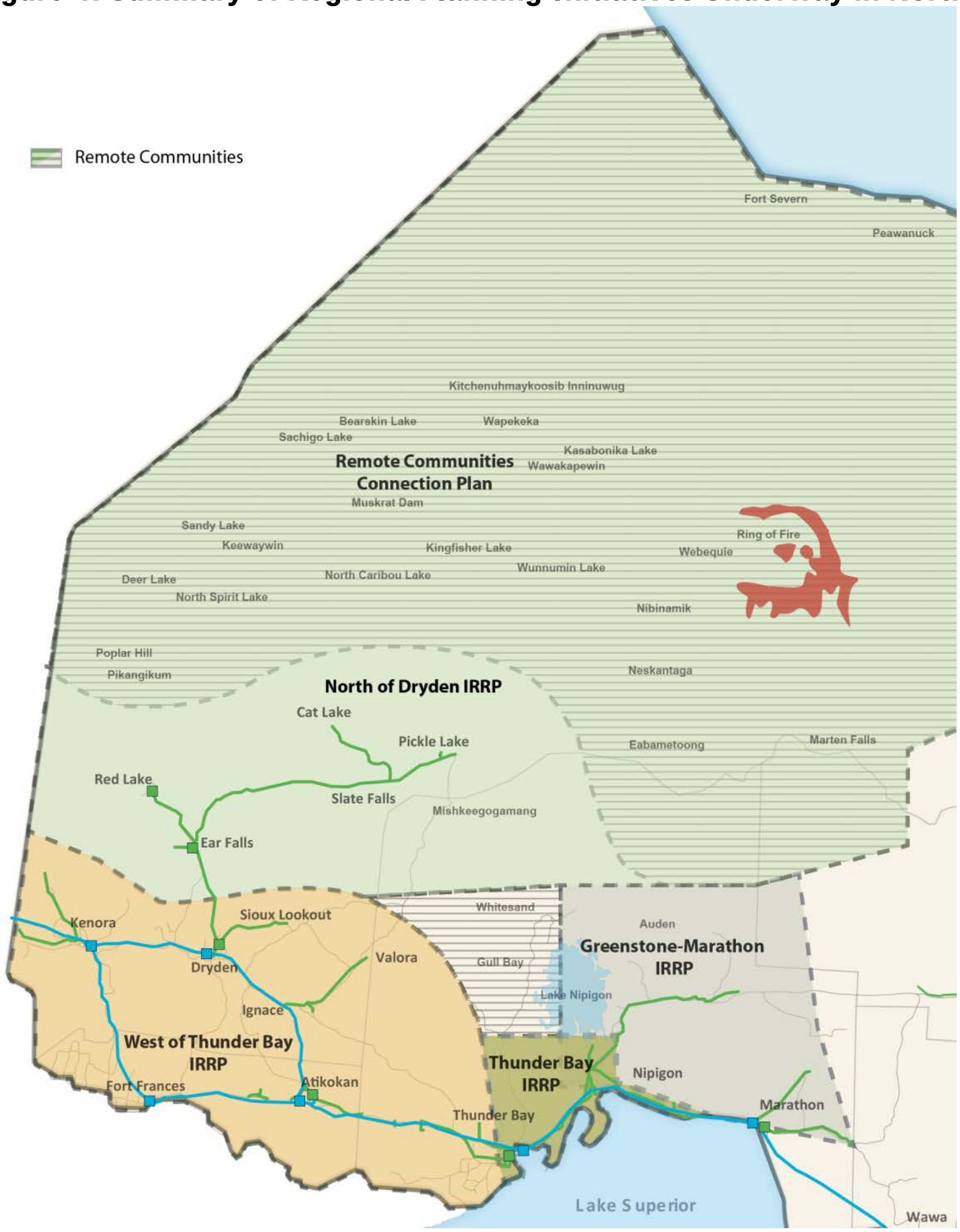
2.1 The North of Dryden Sub-Region

The North of Dryden Integrated Regional Resource Plan (“IRRP”) is one of several electricity planning initiatives that the Ontario Power Authority (“OPA”) is undertaking for the Northwest Ontario region. Figure 4 identifies the IRRP initiatives currently being undertaken by the OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region.

The Thunder Bay IRRP, West of Thunder Bay IRRP and Greenstone-Marathon IRRP were initiated fall 2014. A Scoping Outcome Assessment Outcome Report for northwestern Ontario, which includes the Terms of Reference for three new IRRPs, is available on the OPA’s website, consistent with Ontario Energy Board (“OEB”) requirements. The Terms of Reference for the West of Thunder Bay IRRP and the Greenstone-Marathon IRRP include considerations for relationships with the North of Dryden IRRP.

The North of Dryden sub-region is a natural resource rich area in northwestern Ontario, with existing mining, forestry, and hydroelectric generation operations, as well as potential for substantial new resource development. Mining sector expansion, including expansion of existing mines as well as the development of new mines, is a major driver for electricity demand growth in the area, both at mine sites and through growth in industries that support the mining sector. Another major driver for electricity demand growth in the area is the economic connection of remote First Nations communities (“remote communities”) to the provincial transmission grid, which are currently served by isolated diesel generation systems.

Figure 4: Summary of Regional Planning Initiatives Underway in Northwest Ontario



The transmission system supplying the North of Dryden sub-region is currently at capacity. This IRRP recommends options to provide new high voltage electrical capacity to meet near-term growth, while providing options to meet future growth as it becomes more certain. These near-term recommendations are presented as action items for immediate or early deployment. Options to address potential longer-term needs are also identified, but the OPA does not make a recommendation on a preferred option at this time, as the longer term still remains uncertain and adequate time is available to continue to monitor the situation closely. The OPA will continue to monitor demand growth and reevaluate longer-term options in future planning cycles for the North of Dryden sub-region. When a decision for the longer-term is required, the OPA will make a recommendation for solutions to be implemented.

The North of Dryden sub-region (shown in more detail in Figure 5) is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario ("MNO"). The southern portion of the area (as shown in Figure 5) is currently served by Ontario's transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest, and Pickle Lake to the northeast. Current mining activity is mostly contained in this portion of the area, and broadly focused around the Towns of Ear Falls, Red Lake and Pickle Lake.

The northern portion of the North of Dryden sub-region (as shown in Figure 5) is comprised of 21 remote communities, one operating mine and the mine development area in the Hudson Bay lowlands known as the Ring of Fire. At present, the mine north of Pickle Lake is connected to the transmission grid by a privately owned transmission line. There are 25 remote First Nations communities that are distant from the existing provincial transmission system and are currently supplied electricity by local diesel generation facilities. On August 21, 2014, an updated draft Remote Community Connection Plan was made available on the OPA website.[9] The Remote Community Connection Plan demonstrates a business case to connect 21 of 25 remote communities that currently rely on diesel generation, to the provincial transmission grid. The business case is based on the avoided cost of diesel fuel. For the purpose of this regional plan, 21 of the 25 communities are assumed to connect to Ontario's transmission system as per the OPA's Remote Community Connection Plan. Communities are expected to begin connecting in the early 2020s.

[9] http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

Figure 5: Map of Northwest Ontario Showing the Existing Transmission System

Distribution connected customers in the North of Dryden sub-region are served by Hydro One’s distribution system. There are also a number of large industrial customers that are connected directly to the transmission system in the area and served by Hydro One’s transmission system.

2.2 Purpose and Scope of the IRRP

This regional plan assesses the near-term and medium- to long-term electricity supply needs of the North of Dryden sub-region and identifies the options which are available to address these needs in a cost-effective, reliable, and timely manner. The regional plan is intended to identify alternatives and recommended options to local customers, proponents, and local government so development work may proceed. Proponents may also choose to use this regional plan to support the regulatory proceedings they will undertake to seek approval for their projects.

Regional planning for the North of Dryden sub-region began before the OEB's formalized regional planning process was developed as part of the Renewed Regulatory Framework for Electricity ("RRFE"). Consequentially the North of Dryden IRRP does not have a corresponding Scoping Assessment Outcome Report. The North of Dryden IRRP is considered a "transition plan" as per the Planning Process Working Group ("PPWG") report on Regional Planning to the OEB. This version of the North of Dryden IRRP has transitioned and aligned with OEB requirements for the IRRPs as per the OPA's license.

In 2010, the OPA, Hydro One and the Independent Electricity System Operator ("IESO") began working together to assess the ability of the electricity system in the North of Dryden sub-region to meet forecast growth over the near, medium and long term, and to develop integrated plans to address needs that have been identified. Since beginning this planning work, the OPA has engaged existing and potential customers in the area to identify the size and scope of their future electricity needs in the North of Dryden sub-region. The IESO has also completed a number of System Impact Assessments ("SIAs") and feasibility studies for customers requesting additional capacity.

In addition to the regional planning requirements outlined by the OEB, the Minister of Energy identified in the 2010 Long-Term Energy Plan ("LTEP") that the OPA would develop plans to enable the connection of remote First Nations communities, and identified the development of a new transmission line to Pickle Lake to be a priority transmission project, with the scope and timing to be determined by OPA. In February 2011, the OPA received an updated Supply Mix Directive ("SMD") from the Minister of Energy. The updated SMD requires that the OPA develop a plan to connect remote First Nation communities north of Pickle Lake. In December 2013, the Ministry of

Energy released the second LTEP which reiterated that connecting remote First Nation communities in northwestern Ontario is a priority.

Since 2009, the OPA has been working with remote First Nations communities through the Northwestern Ontario First Nation Transmission Planning Committee ("NWOFNTPC") to identify communities that are economic to connect to the provincial transmission system. Through this partnership, planning is underway for connecting most of these communities to the grid and for developing local solutions for the remaining communities to cost-effectively reduce their reliance on diesel fueled generation.

The North of Dryden IRRP is affected by connection of remote communities in two primary ways:

1. The transmission facilities serving the area must be capable of supplying the electrical demand resulting from the connection of these remote communities; and

2. Options for coordinating connection with mining developments, especially in the Ring of Fire area, must be investigated in accordance with assumptions in the Remote Community Connection Plan.

As new information on the connection of the remote communities becomes available, the North of Dryden IRRP will be updated accordingly and consistent with the regional planning process and PPWG report.

It should also be noted that regional plans consider overall societal costs[10] in determining the least cost options for supplying a study area. This analysis does not

[10]Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment etc, operating and maintenance, fuel etc.), but excludes the cost of land, taxes, and potential Impact Benefit Agreements that may be reached with affected First Nations, which proponents may be required to pay. cont'd...

consider how the allocation of costs attributable to individual customers in the area may affect their decision to pursue the societal least cost options. The final determination of cost allocation between parties will be determined by the appropriate regulatory process or commercial agreement. For example, cost allocation of transmission and distribution infrastructure is made by the OEB, benefitting customers, and/or transmitters and distributors in the area in accordance with the rules set out in the Transmission System Code ("TSC") and Distribution System Code ("DSC").

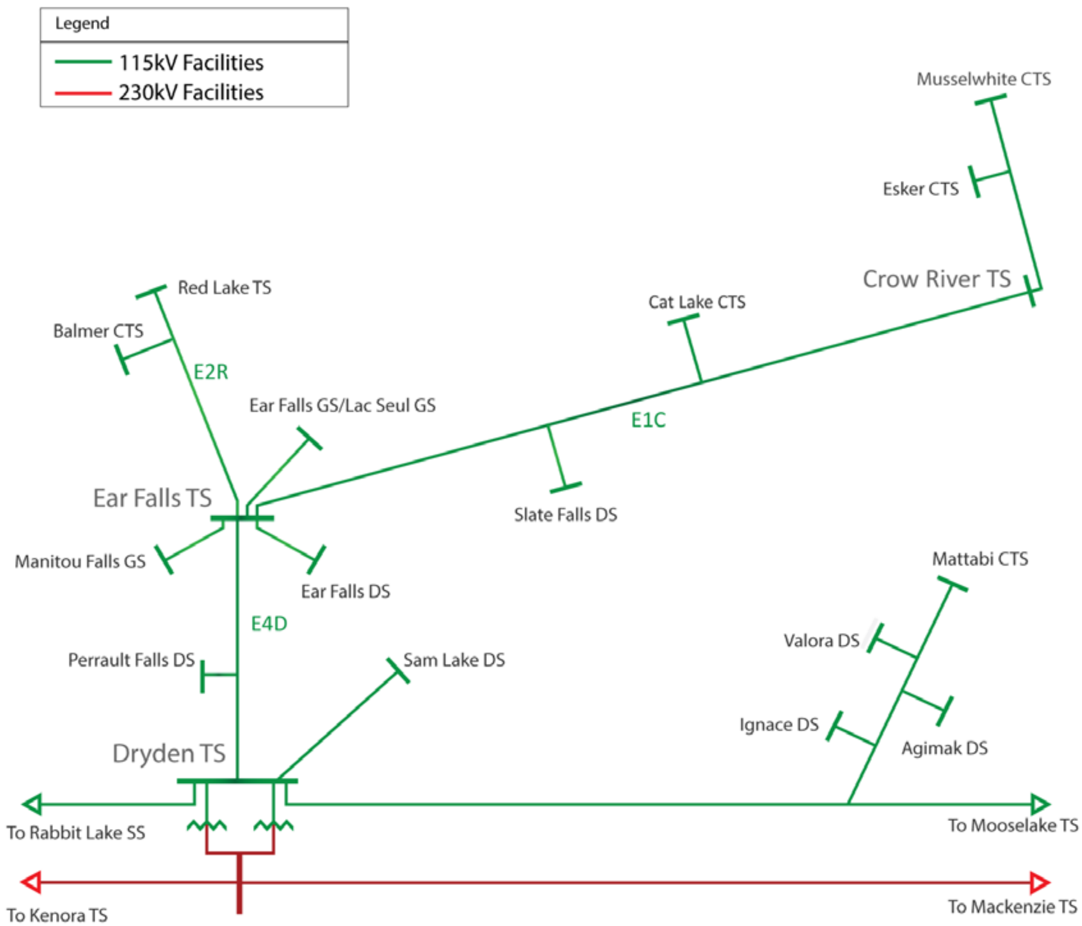
Other planning activities for the region will consider supply needs to the Dryden area for supply of expected load growth in the North of Dryden sub-region. Some of the planning and development work that is underway to ensure an adequate supply is available in the overall Northwest region includes development work being undertaken by NextBridge Infrastructure for an expanded East-West Tie ("EWT"), the May 30, 2014 Northwest Request for Information ("NW-RFI"), and the regional planning initiatives summarized in Figure 4.

...Governments (and their agencies) undertake (or mandate) projects of infrastructural, environmental, or health and safety enhancement in the wider public interest, assessing project merit in terms of the long-term return to current and future generations of society as a whole, using a Real Social Discount Rate (Real "SDR"). The OPA uses a 4% Real Social Discount Rate for determining the present value of options over the planning period.

3 NORTH OF DRYDEN TRANSMISSION AND GENERATION FACILITIES

Currently, electricity customers in the North of Dryden sub-region are supplied by a single-circuit 115 kV radial transmission line (“E4D”) emanating from Dryden TS and by local hydroelectric generation. Dryden TS is a major supply station for this area, where the voltage is stepped down from the regional 230 kV system to 115 kV to serve local community and industrial customers as shown in Figure 6 below.

Figure 6 Existing North of Dryden Transmission System



At Ear Falls TS, the 115 kV supply branches to the north, east, and west to supply customers and incorporate generation in the area. Hydroelectric generation is connected to the transmission system at Ear Falls generating station ("GS") (17 MW Ear Falls + 12.1 MW Lac Seul) and at Manitou Falls GS (73.1 MW). To the north of Ear Falls, the E2R transmission line ("E2R") supplies Red Lake area mining and community customers. East of Ear Falls, the E1C transmission line ("E1C") supplies the Town of Pickle Lake, Cat Lake First Nation, Slate Falls First Nation, Mishkeegogamang First Nation, as well as a mine via a privately-owned 115 kV transmission line ("M1M").

For the purposes of this regional plan, the North of Dryden sub-region is divided into three main subsystems, as shown in Figure 7, the Pickle Lake subsystem, the Red Lake subsystem, and the Ring of Fire subsystem. At present, the Ring of Fire subsystem has no transmission infrastructure and is not connected to the provincial transmission grid, and the Pickle Lake subsystem is supplied downstream of the Red Lake subsystem from Ear Falls via E1C.

The Pickle Lake subsystem includes all demand planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as a mine north of Pickle Lake and any new customers that may connect in the Pickle Lake area in the future. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are identified to connect to Pickle Lake in the 2014 Remote Community Connection Plan.

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities north of Red Lake that are identified as being economic to connect to Red Lake TS in the 2014 Remote Community Connection Plan. As mentioned previously, there is 102.2 MW of hydroelectric generation at Ear Falls GS and Manitou Falls GS.

Figure 7: North of Dryden Subsystems

The Ring of Fire subsystem does not include any existing transmission facilities. The subsystem includes five remote communities that are identified for connection in the 2014 Remote Community Connection Plan as well as potential future industrial customers at the Ring of Fire mine development area.

Due to the current system configuration, when a transmission line in the North of Dryden sub-region is forced out of service all load connected to it is lost. In the event that E4D is removed from service, some of the North of Dryden system can be restored by islanded[11] hydroelectric generation in the Ear Falls area until E4D is returned to service. While the area is islanded from the system and supplied by local generation, the amount of load that can supplied is limited to the available generation output.

Historically, the reliability of electricity supply to some customers in the North of Dryden sub-region has been worse than the average for other customers in northwestern Ontario. Specifically, customers in the Pickle Lake subsystem (currently supplied by E1C) have experienced, on average, 14 unplanned outages per year over the past 10 years.[12] This compares to an average of about three unplanned outages per year for customers served by the other 115 kV lines in northwestern Ontario.[13] Planning for the north of Dryden system includes consideration of this historical performance.

[11] Islanded: when one part of the system is disconnected and operated separately from the rest of the Ontario electricity system.
[12] Hydro One Networks Inc. through correspondence.
[13] Hydro One Networks Inc. through correspondence.

4 HISTORICAL ELECTRICITY DEMAND

4.1 Historical Electricity Demand

Demand for electricity in the North of Dryden sub-region is driven by a number of factors including mining and forestry activity, as well as local community growth. Mining sector expansion is the primary driver of growth in electricity demand in the area. The north of Dryden area is currently winter-peaking. As shown in Figure 8, peak demand in the North of Dryden sub-region has been growing by approximately 1.9% since 2004. Historical demand includes only the Pickle Lake and Red Lake subsystems, since the Ring of Fire subsystem has not yet developed beyond the five remote communities located east of Pickle Lake. Historical demand figures also do not include remote community demand, since they are not currently connected to the provincial transmission system.

Figure 8: North of Dryden Historical Transmission Connected Demand

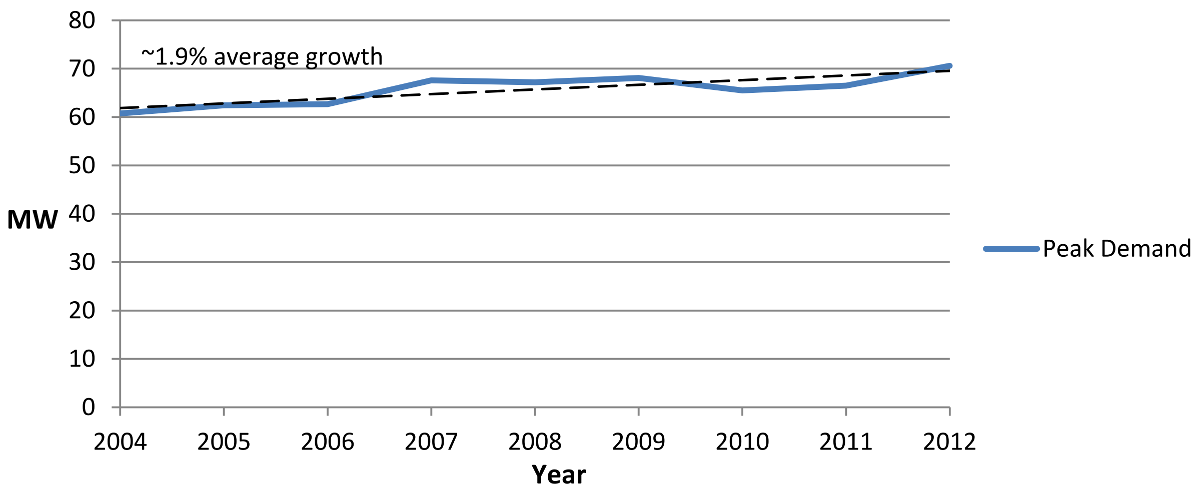
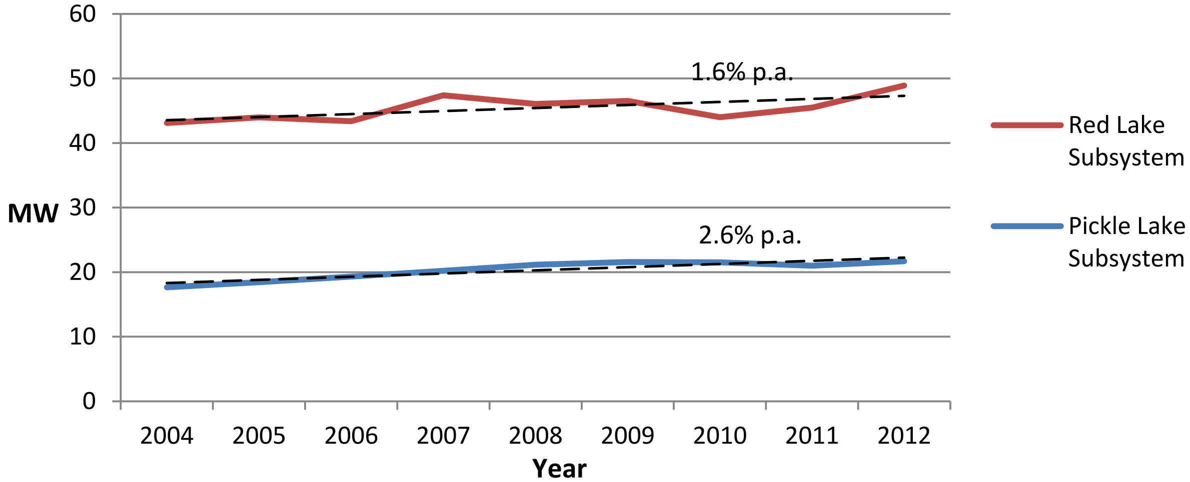


Figure 9 shows that growth in electricity demand has also varied between the Red Lake and Pickle Lake subsystems, with annual growth in electricity demand averaging 1.6% in the Red Lake subsystem and 2.6% in the Pickle Lake subsystem between 2004 and 2012.

Figure 9: North of Dryden Historical Demand by Subsystem



In 2012, 61 MW of capacity was allocated to customers in the Red Lake subsystem, while 24 MW of capacity was allocated to customers supplied in the Pickle Lake subsystem. When the load of the remote communities in each subsystem are added to the connected load, the total load in 2012 increases to 67 MW in the Red Lake subsystem and 31 MW in the Pickle Lake subsystem. At present, no customers in the Ring of Fire subsystem are connected to the provincial grid; however, the combined demand of the five remote communities in the subsystem was about 3 MW in 2012.

4.2 Existing Distributed Generation Resources

Distributed generation is small-scale generation sited close to load centers; it helps supply local energy needs while at the same time contributing to meeting provincial demand. Along with other OPA procurement processes, the introduction of the *Green Energy and Green Economy Act, 2009* and the associated development of the Feed-in Tariff ("FIT") program have encouraged the development of distributed generation resources in Ontario. These procurements take into consideration the system need for generation as well as cost.

Presently, there are five contracted microFIT projects, and one contracted FIT project in the North of Dryden sub-region. All of these projects are located in the Red Lake subsystem. Of these projects, four microFIT solar projects are located in Red Lake with a total contract capacity of 39.3 kW and one microFIT solar project is in Ear Falls with a contract capacity of 10 kW. Analysis of the ability of solar resources in the North of Dryden sub-region to contribute to meeting local demand during the fall months has been estimated to be 5% of contract capacity. Therefore, these units are expected to contribute 2.5 kW to the LMC of the Red Lake subsystem. The FIT project is the Trout Lake River FIT small hydro project, a run of river hydroelectric project near Ear Falls, with a contract capacity of 3.75 MW[14]. The dependable generation level for this project (see Appendix 10.3.2) and its contribution to the LMC of the Red Lake subsystem is assumed to be 0 MW.[15] In total, the contribution of these DG units to the LMC of the Red Lake subsystem is expected to be 2.5 kW (0.0025 MW).

Currently, there are a number of diesel generators that provide backup/emergency supply at mine sites, which are required for health and safety purposes. Generally, these units are not configured for grid connection and thus are not currently available to supply the system. Even if they were configured to connect to the grid, there may be other limitations on their ability to reliably supply load customers on a regular basis including: their age, efficiency, level of emissions, prescribed limits in their operating approvals and their operating and maintenance costs. These units may have some potential to operate as short-term demand management resources, but given the available information they cannot be relied upon to provide the capacity and energy required to meet the needs of the North of Dryden sub-region. Therefore, they have not been considered further in this regional plan.

The Request for Information for Electricity Resources in Northwestern Ontario ("NW-RFI") was issued to better understand the availability of all potential resources in northwest Ontario including the North of Dryden sub-region, with particular focus on the

[14] Trout Lake River GS, is a contracted FIT small hydro project currently under development, with an expected commercial operation date of Q1 2015.
[15] The performance of the facility during drought conditions has not yet been determined, however, the anticipated contribution based on similar facilities in the area, is much less than the tolerance of the modelling software used for this study.

interim period to 2020. The OPA has received submissions to the NW-RFI. Generation options in this plan have considered the relevant NW-RFI submissions. Should new information become available it will be included at the next update of this regional plan.

5 FORECAST ELECTRICITY DEMAND

To develop the demand forecast the OPA worked with Hydro One (the transmitter and local distribution company serving the North of Dryden sub-region), existing and potential transmission connected industrial customers around Ear Falls, Red Lake, and Pickle Lake[16] and the Ring of Fire, municipalities, business associations, as well as remote First Nations communities in northwest Ontario.

5.1 New Demand from Connection of Remote First Nation Communities

The findings of the Remote Community Connection Plan indicate that due to the high and growing cost of diesel fuel as well as the high cost of operating and maintaining remote diesel generation systems, transmission connection of up to 21 remote communities can avoid substantial future costs of about $1 billion over 40 years and therefore economically justifies the connection of the corresponding 21 remote communities to the provincial transmission grid. For the purposes of this IRRP, it has been assumed that these communities will pursue a connection and therefore includes the demand of the corresponding remote communities in the North of Dryden IRRP forecast. The Remote Community Connection Plan indicates that communities may begin connecting between 2018 and 2020, following the development of required capacity in the North of Dryden sub-region transmission system.

5.2 Residential and Commercial Forecasted Demand

The OPA worked with Hydro One to establish the Residential and Commercial component of the demand forecast in the North of Dryden sub-region. The OPA then removed the industrial component of the load that is connected to the distribution system to determine the forecasted residential and commercial forecasted demand. Hydro One Distribution supplies electricity to customers at the following transformer

[16] The load growth is based on information provided to the OPA by Hydro One Networks Inc. and industrial customers in the North of Dryden sub-region. Hydro One provided information relating to existing distribution facilities North of Dryden; this includes existing community loads and some industrial loads. The OPA worked with existing and potential industrial customers to determine their expected near and long-term electricity needs. The forecast has been shared with Common Voice Northwest’s Energy Task Force among other interested stakeholders.

stations: Perrault Falls DS, Ear Falls DS, Red Lake TS, Crow River DS, and Slate Falls DS. Cat Lake CTS is owned by Cat Lake Power Utility Ltd., and is supplied by Hydro One's transmission system from circuit E1C.

5.3 New and Expanding Mining Projects

The majority of forecasted demand growth in the North of Dryden sub-region is anticipated to be primarily driven by the mining sector.

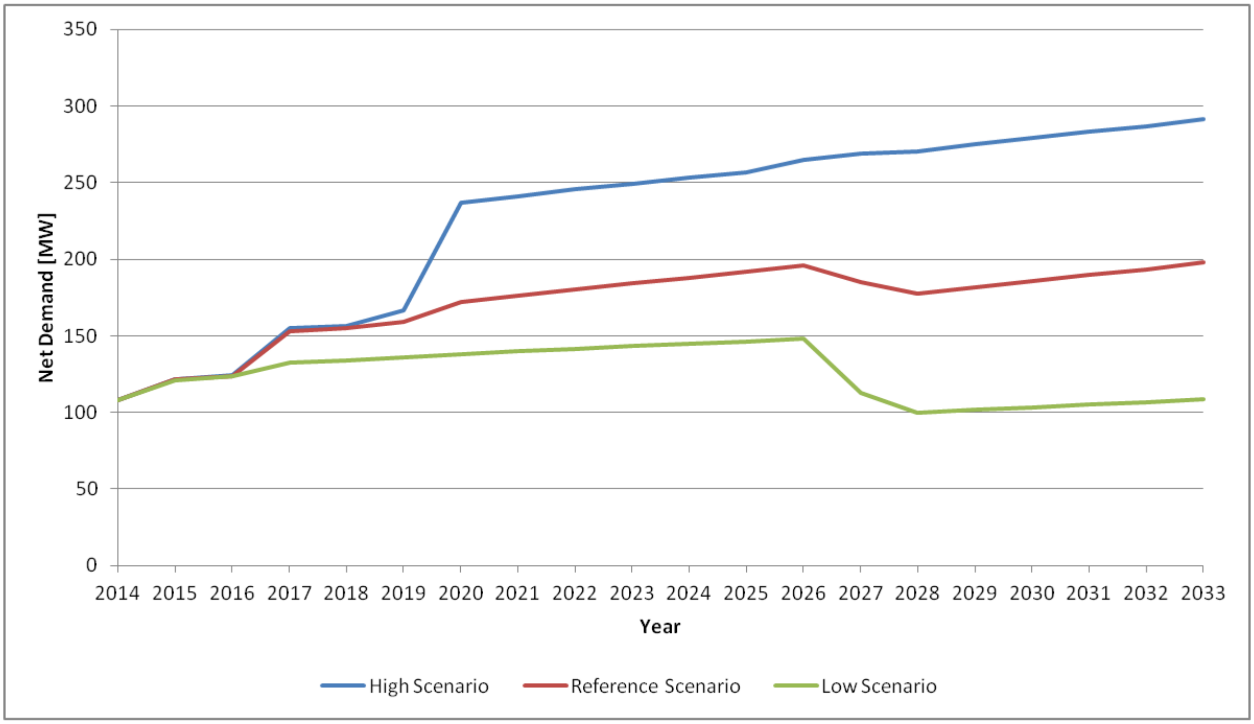
Numerous projects have been proposed in the region, representing a variety of mineral resources, stages of feasibility and development and potential environmental impacts. As mining is a commodity-based industry, there is uncertainty with the timing of mining projects, especially those that are in the relatively early stages of development. This corresponds to uncertainty in the forecasted electrical demand for the area. Recognizing the risk associated with uncertainty in the forecasted demand, the OPA produced three load scenarios. The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information presently available.

Through engagement with the mining companies, mining associations and other stakeholders in the region, and by reviewing available technical documents produced by the mining companies regarding their proposed projects, the OPA categorized projects according to the likelihood that they will be developed within their proposed timelines. The projects have been categorized based on several factors, including:

- Stage of development (e.g. under construction, undergoing an Environmental Assessment ("EA"), still in exploration, etc.)
- Financial feasibility (e.g. results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g. commodity prices, customers and demand)

Figure 10 shows the forecast range over the planning period.

Figure 10: North of Dryden sub-region Net Demand Forecast

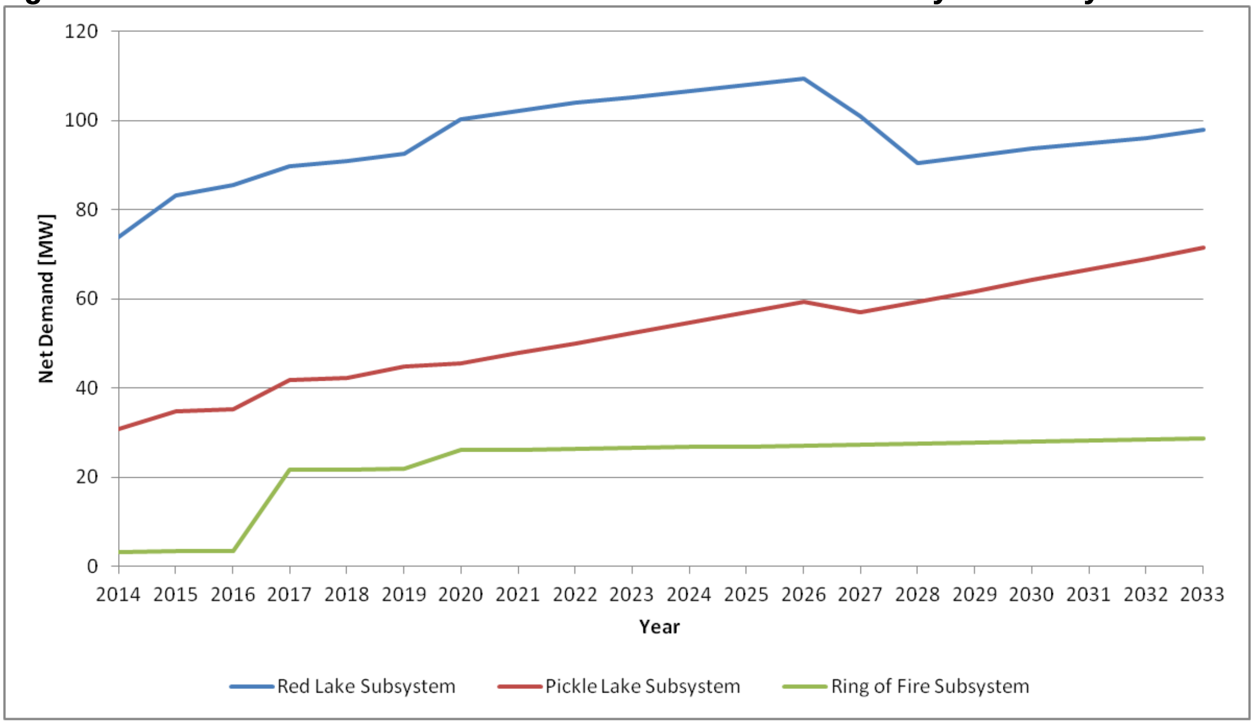


The following descriptions provide the scope of regional activity under the three scenarios.

5.4 Reference Scenario Demand Forecast

Under this scenario, it is assumed that projects currently under construction will be completed and commissioned on schedule. It is assumed that projects with high grade mineral deposits and positive economic assessments will be developed by the timelines specified in their project descriptions with relatively high probability. Projects with potential for extensive environmental impacts are assumed to be unlikely to proceed in the near term as well as projects which are still in the exploration phase. Furthermore, the reference scenario assumes that modest electrical demand driven by the mining sector in the Ring of Fire area is likely to appear before 2024.

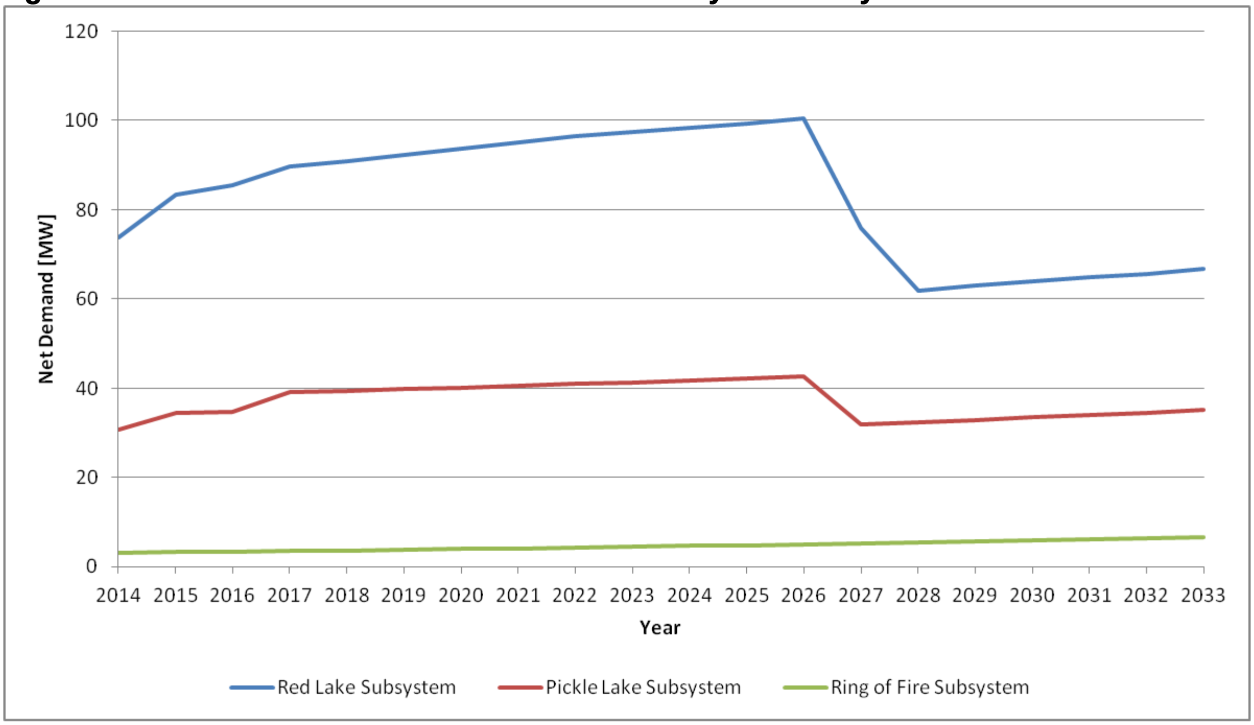
Figure 11: Reference Scenario Demand Forecast for North of Dryden Subsystems



5.5 Low Scenario Demand Forecast

This scenario assumes only the most mature and developed projects (e.g. currently under construction or applying for a leave to construct) are likely to be developed before 2024. It is assumed that other projects with a positive economic assessment will be fully developed with a 50% probability. Early stage exploration projects and projects with marginal economics or environmental, infrastructure and/or accessibility hurdles are assumed to not be developed. This scenario also assumes the Ring of Fire will not be developed before 2034.

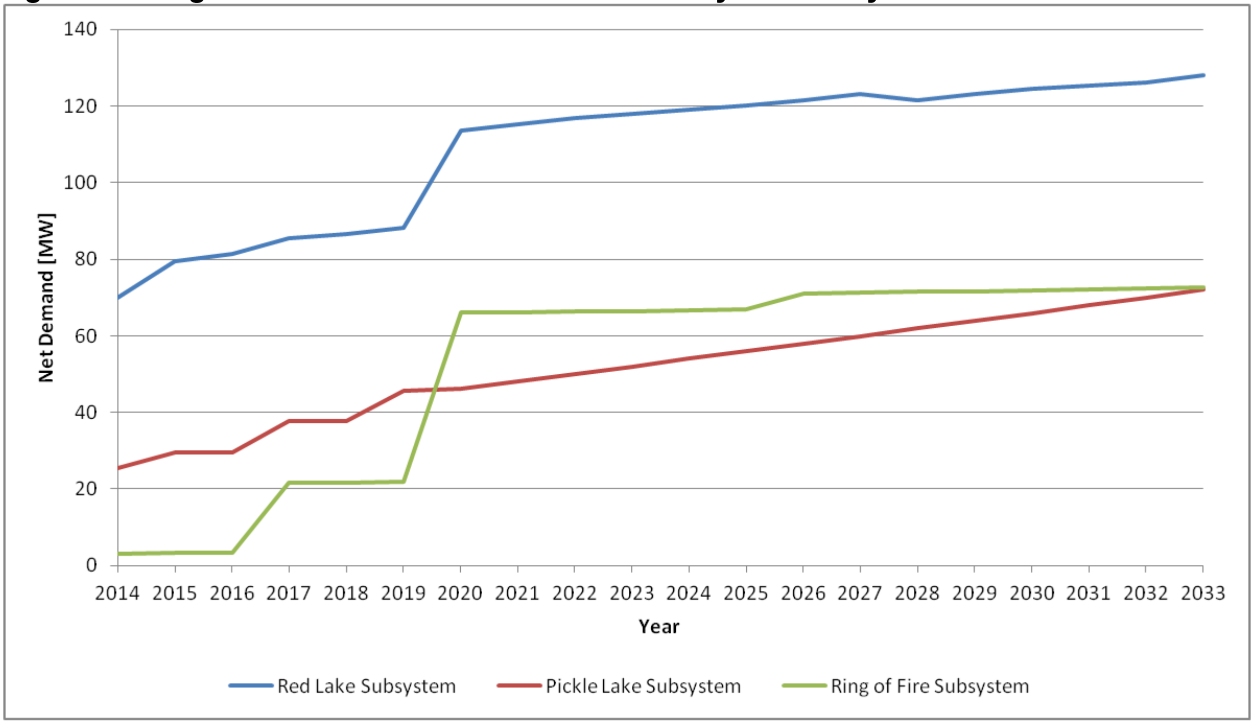
Figure 12: Low Demand Forecast for North of Dryden Subsystems



5.6 High Scenario Demand Forecast

Under the high scenario, most proposed projects are considered likely to be developed and commissioned in the near term. This scenario assumes sufficiently high commodity prices will provide financial feasibility to many projects that may otherwise be considered marginal or uneconomic. The high scenario also assumes an extensive, near- to medium-term build out of the Ring of Fire area, and that multiple mines will be operating in the region by 2020. The expansion of the mining sector is assumed to result in additional expansion of the residential sector in the region, which is also captured in this scenario.

Figure 13: High Demand Forecast for North of Dryden Subsystems



The OPA will continue to monitor electricity demand growth and work with existing and potential customers to maintain up to date electrical demand forecasts for the area. This information will be used to develop regular updates to the North of Dryden IRRP as per the formalized OEB Regional Planning Process.

5.7 North of Dryden Sub-Region Net Electricity Demand

A summary of the net demand forecast scenarios for the North of Dryden sub-region is presented in Table 3.

Table 3: Detailed Net Demand Forecast[17]

NET FORECAST [MW]

Red Lake Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	74	83	85	90	91	93	118	120	122	123	125	126	127	129	128	130	131	133	134	136
Reference Scenario	74	83	85	90	91	93	100	102	104	105	107	108	109	101	90	92	94	95	96	98
Low Scenario	74	83	85	90	91	92	94	95	96	97	98	99	100	76	62	63	64	65	66	67

Pickle Lake Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	31	35	35	44	44	52	53	55	57	60	62	64	66	69	71	73	76	78	81	83
Reference Scenario	31	35	35	42	42	45	46	48	50	52	55	57	59	57	59	62	64	67	69	71
Low Scenario	31	34	35	39	39	40	40	41	41	41	42	42	43	32	32	33	33	34	35	35

Ring of Fire Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	3	3	3	22	22	22	66	66	66	67	67	67	71	71	71	72	72	72	72	73
Reference Scenario	3	3	3	22	22	22	26	26	26	27	27	27	27	27	27	28	28	28	28	29
Low Scenario	3	3	3	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	7

[17] Source: OPA developed forecast as described above. Also includes forecasted values provided by Hydro One.

6 NEEDS IN THE NORTH OF DRYDEN SUB-REGION

Planning for the reliable supply of electricity requires anticipating potential equipment outages before they occur and designing a power system that limits the impacts to consumers, based on good utility practices as outlined in the OEB's TSC. This is accomplished through the application of planning criteria. In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC")[18].

In accordance with ORTAC, the transmission system shall have sufficient capability under peak demand conditions to withstand specific outages while keeping voltages, and equipment loading within applicable limits. The maximum demand that can be supplied by an electricity system in a defined area is known as the load meeting capability ("LMC") of that area. Where an area is served by a single transmission line and local generation, the LMC is determined as the capability of the transmission line during normal operation, with the dependable level of local generation respecting the loss of the largest generating unit. If the area is served by a single transmission line without local generation, the LMC is determined as the capability of the transmission line during normal operation since the loss of the single line will result in the total loss of all connected load. The following factors are considered when determining the LMC of a transmission system serving an area:

- the configuration of the system;
- the capabilities of individual elements comprising the system, for the north of Dryden system, this includes the limits of the transmission lines and the dependable levels of hydroelectric generation;[19] and

[18] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf
[19] the dependable level of the existing run of river hydroelectric generation (that is available during drought water flow conditions) is assumed to be available. Details regarding the method for determining the dependable level of hydroelectric and other renewable generation resources for the IRRP are provided in Appendix 10.3.2. Drought conditions are expected to occur about one year in every 10 years and can persist for several months at a time, when watersheds are at their lowest levels in the late summer, fall and early winter months.

- the distribution of demand in the area being supplied.

In general, the greater the distance a given electrical load is located from the inter-regional transmission system (bulk system) supply point (Dryden and/or Marathon or east of Nipigon), the lower the LMC of the system will be. This is due to losses and the need to maintain system voltages within criteria.

6.1 Capability of the Existing North of Dryden System to Supply Forecast Electricity Demand

At present the entire North of Dryden system is supplied from Dryden TS (via E4D) and supported by hydroelectric generation at Ear Falls. The application of ORTAC to the 115 kV transmission system serving the North of Dryden results in an LMC of 85 MW, based on the current line ratings and available dependable hydroelectric generation resources in the Ear Falls area. Existing customers have been allocated 85 MW of capacity on the system and thus the area has reached its capacity limit or LMC. Of this LMC, 24 MW is allocated to the Pickle Lake subsystem and the remaining 61 MW serves the Red Lake subsystem. Mining load in the Ring of Fire subsystem has yet to develop, and the five remote communities in the subsystem are currently supplied by isolated diesel generation. Since the Remote Community Connection Plan identifies that it is economic to connect these communities and there is currently no transmission system serving the Ring of Fire subsystem, the corresponding LMC of the existing provincial power system is 0 MW.

For new customer load to be connected and served in any of the subsystems, additional supply capacity is required. The new capacity needed in order to meet forecast demand growth as provided by Hydro One Distribution, existing and future industrial customers, and the Remote Community Connection Plan (net of planned conservation), is summarized in Table 4 below.

Table 4: Summary of Capacity Needs to Meet the Net Demand Forecast for each Subsystem

Red Lake Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
High Scenario	74	83	85	90	91	93	118	120	122	123	125	126	127	129	128	130	131	133	134	136
Need - High Scenario	*13*	*22*	*24*	*29*	*30*	*32*	*57*	*59*	*61*	*62*	*64*	*65*	*66*	*68*	*67*	*69*	*70*	*72*	*73*	*75*
Reference Scenario	74	83	85	90	91	93	100	102	104	105	107	108	109	101	90	92	94	95	96	98
Need - Reference Scenario	*13*	*22*	*24*	*29*	*30*	*32*	*39*	*41*	*43*	*44*	*46*	*47*	*48*	*40*	*29*	*31*	*33*	*34*	*35*	*37*
Low Scenario	74	83	85	90	91	92	94	95	96	97	98	99	100	76	62	63	64	65	66	67
Need - Low Scenario	*13*	*22*	*24*	*29*	*30*	*31*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*15*	*0*	*0*	*0*	*0*	*0*	*0*

Pickle Lake Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
High Scenario	31	35	35	44	44	52	53	55	57	60	62	64	66	69	71	73	76	78	81	83
Need - High Scenario	*7*	*11*	*11*	*20*	*20*	*28*	*29*	*31*	*33*	*36*	*38*	*40*	*42*	*45*	*47*	*49*	*52*	*54*	*57*	*59*
Reference Scenario	31	35	35	42	42	45	46	48	50	52	55	57	59	57	59	62	64	67	69	71
Need - Reference Scenario	*7*	*11*	*11*	*18*	*18*	*21*	*22*	*24*	*26*	*28*	*31*	*33*	*35*	*33*	*35*	*38*	*40*	*43*	*45*	*47*
Low Scenario	31	34	35	39	39	40	40	41	41	41	42	42	43	32	32	33	33	34	35	35
Need - Low Scenario	*7*	*10*	*11*	*15*	*15*	*16*	*16*	*17*	*17*	*17*	*18*	*18*	*19*	*0*	*0*	*0*	*9*	*10*	*11*	*11*

Ring of Fire Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Scenario	3	3	3	22	22	22	66	66	66	67	67	67	71	71	71	72	72	72	72	73
Need - High Scenario	*3*	*3*	*3*	*22*	*22*	*22*	*66*	*66*	*66*	*67*	*67*	*67*	*71*	*71*	*71*	*72*	*72*	*72*	*72*	*73*
Reference Scenario	3	3	3	22	22	22	26	26	26	27	27	27	27	27	27	28	28	28	28	29
Need - Reference Scenario	*3*	*3*	*3*	*22*	*22*	*22*	*26*	*26*	*26*	*27*	*27*	*27*	*27*	*27*	*27*	*28*	*28*	*28*	*28*	*29*
Low Scenario	3	3	3	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	7
Need - Low Scenario	*3*	*3*	*3*	*4*	*4*	*4*	*4*	*4*	*4*	*5*	*5*	*5*	*5*	*5*	*5*	*6*	*6*	*6*	*6*	*7*

There is a near-term (present to 2018) need for additional capacity (incremental LMC) in each subsystem. The summary of capacity needs indicates that there will be need for 18 MW and up to 20 MW in the Pickle Lake subsystem, 30 MW in the Red Lake subsystem and 22 MW in the Ring of Fire subsystem in the near term.

The majority of forecast demand growth for the North of Dryden sub-region is expected to occur in the medium-term period between 2019 and 2023. This is the period when remote communities and most new mines are expected to connect their load to the system. The long term is characterized by steadily increasing demand over the remainder of the forecast period (2024 to 2033).

In the medium term, capacity needs in the Pickle Lake subsystem are forecast to be 28 MW and up to 36 MW, and up to 59 MW by the end of the planning period in 2033. In the Red Lake subsystem needs are forecast to be 44 MW and up to 62 MW in the medium term, and up to 75 MW by the end of the planning period in 2033.

The capacity need for the Ring of Fire subsystem, which includes potential mines at the Ring of Fire and the connection of five remote communities east of Pickle Lake, is driven by when and if mines connect to the transmission system. If the mines do not connect, then only the demand of the five remote communities will need to be supplied by the system. This is forecast to be 4 MW at the time of connection and up to 7 MW by the end of the planning period in 2033. If the potential Ring of Fire area mines that are considered in the load forecast develop, the capacity need for the Ring of Fire subsystem is forecast to be up to 73 MW by the end of the planning period.

The near-, medium- and long-term capacity needs of each subsystem are summarized in Table 5 below.

Table 5: Summary of Incremental Capacity Needs by Subsystem[20]

Subsystem	Near-term Capacity Needs (Present to 2018 in MW)			Medium-term Capacity Needs (2019-2023 in MW)			Long-term Capacity Needs (2024-2033 in MW)		
	High	Reference	Low	High	Reference	Low	High	Reference	Low
Pickle Lake	20	18	15	36	28	17	59	47	11
Red Lake	30	30	30	62	44	36	75	48	39
Ring of Fire	22	22	4	67	27	5	73	29	7

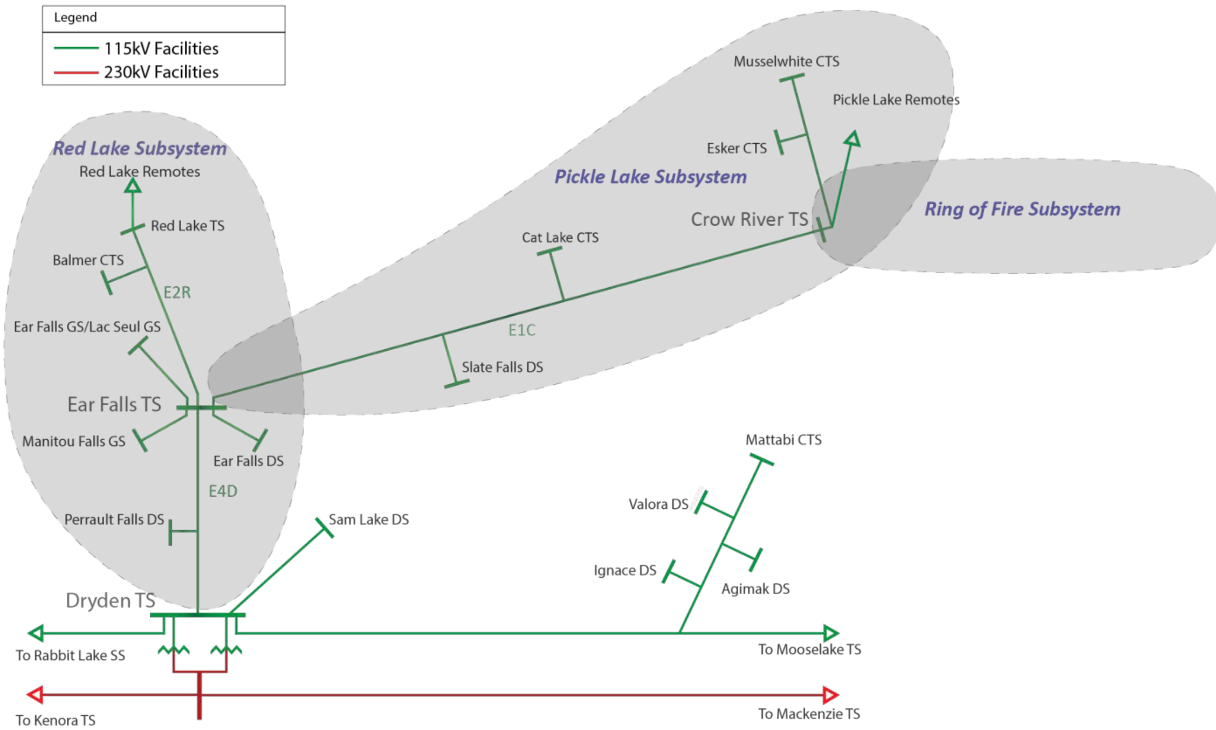
[20] Includes LMC required to supply remote communities that are economic to connect.

6.2 Interdependence between Subsystems

Due to the existing connection of the Pickle Lake subsystem to the Red Lake subsystem at Ear Falls, there is an existing interdependency between these subsystems. Identifying the interrelationships between subsystems is necessary because the supplying subsystem will need to have sufficient capacity to serve the needs of both subsystems. If the Pickle Lake subsystem is supplied completely by a new dedicated transmission connection, then it would be possible (and advantageous during drought conditions) to open the connection between Pickle Lake and Ear Falls (on E1C) and remove this interdependency.

Further, if the Pickle Lake subsystem has sufficient capacity in the future and the Ring of Fire subsystem is connected to Pickle Lake, then a new interdependency between the Pickle Lake and Ring of Fire subsystems would be created. These relationships are highlighted on the map below in Figure 14, which shows the amount of load in the dependent subsystem that is or would be served from the supplying subsystem. The ultimate capacity needed in the Red Lake and Pickle Lake subsystems will depend on the how the Pickle Lake and Ring of Fire subsystems are supplied in the future.

Figure 14: North of Dryden Subsystems and Points of Intersection



7 OPTIONS AND ALTERNATIVE DEVELOPMENT

This section identifies and evaluates options for developing integrated solutions that meet the needs identified in Section 6. Options applicable for all subsystems are described first, subsystem-specific options are then discussed. The options for the Pickle Lake subsystem are then evaluated,[21] followed by those of the Red Lake subsystem and the Ring of Fire subsystem. The options for addressing the needs of the North of Dryden sub-region are divided into those that can meet near-term needs (present-2018) and those which can meet the medium- and long-term needs (2019-2033) for each subsystem. Technically viable options are identified and evaluated in the context of their ability to meet the needs of each subsystem based on cost,[22] ability to meet reliability criteria, incremental capacity enabled, and in-service date.

7.1 Conservation, Renewable and Distributed Generation

Opportunities for Further Cost Effective Conservation in the North of Dryden sub-region

Conservation is important in managing the demand in the North of Dryden sub-region. However, the high levels of load growth anticipated for the sub-region, resulting from connection of new industrial customers and the remote communities require the incorporation of supply-side solutions such as new transmission, distribution and/or generation facilities in the near term. New industrial facilities are assumed to install relatively efficient equipment from the beginning given the inherent economic benefits and the improved codes and standards.

[21] The Pickle Lake subsystem is assessed first because of its interdependence with both Red Lake and Ring of Fire subsystems. Decisions for serving the Pickle Lake subsystem will impact the capacity needs for the Red Lake subsystem and available options for the Ring of Fire subsystem.

[22] The costs represented in this report are incremental to costs that would have otherwise been incurred for the overall Ontario power system generation capacity needs. The Ontario electricity system will require incremental generation capacity to reliably serve all Ontario customers during peak demand periods by about 2018. Generation resources developed in the North of Dryden sub-region would contribute to meeting this provincial need. Cost for generation in the North of Dryden area is represented as the incremental cost above the least-cost generation option for Ontario. Details of costing methodology can be found in Appendix 10.4.

The OPA evaluates, measures and verifies ("EM&V") conservation program savings. Moving forward, the OPA will continue to monitor conservation achievement in the North of Dryden sub-region and look for opportunities for further cost effective conservation to address supply capacity needs of the area over the medium and long term.

In Achieving Balance: Ontario's Long-Term Energy Plan ("LTEP 2013"), the government established a provincial Conservation and Demand Management ("CDM") target of 30 TWh in 2032. To assist the government in achieving this target, LTEP 2013 also committed to establishing a new six-year Conservation First Framework beginning in January 2015. Meeting these targets was included in establishing the needs described in Section 6. These targets apply to currently grid-connected communities and customers. The Conservation included in the net demand forecast for each subsystem is provided in Table 6 below. For remote communities, conservation opportunities are considered in more detail in the Remote Community Connection Plan.

Table 6: Forecasted Conservation Savings in North of Dryden Sub-Region

	2014	2019	2024	2029	2033
Pickle Lake Subsystem	0.1 MW	0.5 MW	1.2 MW	2.0 MW	2.6 MW
Red Lake Subsystem	0.2 MW	1.1 MW	2.6 MW	4.0 MW	5.3 MW
Ring of Fire Subsystem	0.0 MW	0.2 MW	0.4 MW	0.7 MW	0.9 MW

It is anticipated that the energy efficiency savings identified in Table 6 above will be achieved mainly through measures aimed at the current load base and the load added through connection of the remote communities. The 9 MW in reduced peak demand represents about a 7% reduction of load in this area. The additional mining load is expected to be built using current codes and standards and will be operating at better energy efficiency compared to older facilities. Thus it is not anticipated that the new mining load will be able to contribute much more to energy efficiency programs. Conservation forecast in the region is derived from the provincial target and is consistent with LTEP 2013.

Given the anticipated electricity demand growth, there are opportunities in the medium to long term for proponents to pursue conservation savings. The following tools and programs could be used to achieve conservation savings in the sub-region.

Recently, the OPA has received direction from the Minister of Energy pertaining to the framework for Conservation programs[23] moving forward:

1. *2015-2020 Conservation First Framework (March 31, 2014):* To remain on track to achieve Ontario's 2013 LTEP CDM target, it is forecasted that 7 TWh needs to be achieved between 2015 and 2020 through Distributor CDM programs enabled by the Conservation First Framework. In addition, transmission-connected customers will continue to have access to OPA CDM programs. The OPA is directed to coordinate, support and fund the delivery of CDM programs through Distributors to achieve a total of 7 TWh of reductions in electricity consumption between January 1, 2015 and December 31, 2020.

2. *Continuance of the OPA's Demand Response Program under IESO management (March 31, 2014):* In LTEP 2013, Ontario signaled that responsibility for existing demand response ("DR") initiatives and introduction of new DR initiatives will be transferred from the OPA to the IESO.

3. *Industrial Accelerator Program (July 25, 2014):* The 5-year Industrial Accelerator Program ("IAP") established through the March 4, 2010 ministerial direction, will conclude on June 23, 2015. The Minister has directed the OPA to deliver the IAP for the period commencing June 23, 2015 through December 31, 2020, with a CDM target of 1.7 TWh for the period.

The spirit of the directive is to provide more opportunity for Local Distribution Companies ("LDCs"), industry, and communities to participate in conservation initiatives

[23] The current framework for Conservation programs does not apply to remote communities. These communities are anticipated for connection post-2020, which is the end of the existing framework.

so a broader scope of programs is expected to be tailored to the local needs of the region.

Each LDC will develop their conservation plans and programs to demonstrate. In assisting LDCs, the OPA has launched an online Tool Kit to provide LDCs with the information and planning resources needed to design an effective CDM plan to serve their customers. One of these resources is the Regional Achievable Potential Calculator which assists the utilities in estimating potential Conservation savings in their service regions. Use of this tool can also achieve an understanding of the potential for further conservation specific to the North of Dryden sub-region.

The IAP is available to industrial customers as a means of achieving conservation savings with financial assistance from the OPA. Given that electricity demand of the industrial sector is significant in the area, this could be a good opportunity for conservation in the sub-region. Also, the IAP program expanded the eligibility to allow commercial and institutional customers. These customers can be directly connected to the grid or connected via an LDC.

Furthermore, the following programs are available to Aboriginal Communities:

- Aboriginal Conservation Program, with the aim to provide customized conservation services designed to help First Nation communities, including remote and northern communities, reduce their electricity use in residential housing, and in commercial and institutional buildings, like stores, schools and band offices. This program will be offered for one additional year (ending December 31, 2015) until such time as LDCs are able to develop a CDM program which recognizes the specific requirements of on-reserve First Nation communities as per the 2015-2020 Conservation First Framework Directive.

- Aboriginal Community Energy Plans program to support Aboriginal participation in Ontario’s energy sector by providing up to $90,000 per community in funding to First Nation or Métis communities for local energy planning activities, with remote communities being eligible for an additional $5,000.

Opportunities for Renewable and Distributed Generation in the North of Dryden sub-region

A high level assessment of the cost of renewable and distributed generation resources to meet the capacity needs of the North of Dryden sub-region was completed, estimating the dependable capacity of hydroelectric (run of river), wind, and solar resources. Dependable capacity refers to the portion of the total installed capacity that can be relied upon to meet local or system peak capacity needs. This refers to 98-percentile output. Based on the dependable capacity, costs were developed for these renewable resources. Based on the cost of other local generation and transmission options that are discussed in the following sub-sections, run of river hydroelectric, wind, and solar are not cost effective solutions for meeting the needs of the North of Dryden sub-region in the near and medium-term periods.

Details of these alternative generation resources are provided in Appendix 10.3.2 and summarized below in Table 7.

Table 7: Summary of Alternative Generation Options

Resource Type	Dependable Capacity	Capital Cost per MW of Dependable Capacity	Levelized Unit Energy Cost[24]	Development Duration
Hydroelectric (Run of River)	15-30%	$16 M-$66 M /MW	$60-$110/MWh	5 to 10 Years
Intermittent Renewables	5-28%	$7.5 M -$100M /MW	$80-$400/MWh	3 Years

While run of river hydroelectric or renewable resources are not cost-effective to meet the North of Dryden sub-region peak capacity needs, there may be opportunity for proponents to develop such projects for broader Ontario supply needs in accordance

[24] Levelized Unit Energy Cost (LUEC) is a method to compare electricity system resources on a $/MWh basis, considering the costs incurred (capital, fixed, variable, fuel, etc.) and the production of energy over the lifetime of the resource, discounted appropriately. LUEC assumes that all energy generated can be delivered without transmission constraints.

with renewable policy objectives for the provincial supply mix as set in the 2013 LTEP. Additionally, the connection of remote communities may provide the opportunity to explore development opportunities in the far north, in the longer term.

The remainder of Section 7 will assess the generation and transmission options that can cost effectively meet the identified capacity needs of the North of Dryden sub-region.

7.2 Summary of Recommended and Assessed Options for Meeting Pickle Lake Subsystem Needs

Based on the following analysis, the OPA recommends that a new 230 kV single circuit line to Pickle Lake be built as soon as possible in order to meet the needs of the Pickle Lake subsystem. Building the new line to 230 kV standards is the most economic option to meet the reference forecast scenario, which is regarded as the most-likely scenario. A line built to 230 kV standards also mitigates the long-term risk associated with higher forecasted demand scenarios and maintains the flexibility to supply the Ring of Fire mining development from Pickle Lake. The OPA also recommends that circuit E1C be opened at Ear Falls as an operational measure when the local system is capacity constrained. This operational measure maximizes the capability of the transmission system in the area, resulting in incremental LMC to the Red Lake subsystem. The capacity constraint is expected to occur during high demand periods coincident with drought hydroelectric conditions.

The following section summarizes the analysis and comparison of options.

Within the context of the North of Dryden IRRP, the Pickle Lake subsystem is assessed first because of its interdependence with both the Red Lake subsystem and the Ring of Fire subsystem as discussed in Section 5.2. Decisions made for serving the Pickle Lake subsystem will impact the capacity needs for the Red Lake subsystem at Ear Falls TS and the options for serving the Ring of Fire subsystem.

As mentioned previously, the Pickle Lake subsystem is currently supplied by the 115 kV line E1C from Ear Falls TS and the subsystem has reached its LMC. The forecasted near-term growth and medium- to long-term growth cannot be met by the existing system and other supply options are required. Identified needs for the Pickle Lake subsystem are summarized in Table 8, below.

Table 8: Needs for Pickle Lake Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	Reference	High
Near term (Present-2018)	***Near term Total 1:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem, and Supply the 5 Communities in the Ring of Fire Subsystem*	***43***	***46***	***48***
	Near term Total 2: *Supply Mining and Community Demand in the Pickle Lake Subsystem and in the Ring of Fire Subsystem*	***43***	***64***	***66***
Medium and long term (2019-2033)	***Medium and long term Total 1:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem, and Supply the 5 Communities in the Ring of Fire Subsystem*	***48***	***78***	***90***
	Medium and long term Total 2: *Supply Mining and Community Demand in the Pickle Lake Subsystem and in the Ring of Fire Subsystem*	***48***	***100***	***156***

The following generation and transmission options have been identified to fully or partially meet these needs.

Table 9: Summary of Options to Meet the Needs for Pickle Lake Subsystem[25]

Options	Capital Cost	PV Option Cost	Incremental Load Meeting Capability [MW]	PV Unit Cost of Utilized Capacity
CNG Generation at Pickle Lake[26,27]	$132 M	$294 M	54	$5.44 M/MW
115 kV line to Pickle Lake[28]	$126 M	$80 M	18 + 35	$1.31 M/MW
230 kV line to Pickle Lake[18]	$167 M	$106 M	54 + 35[29]	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake, Stage 1: operate at 115 kV[18] Stage 2: upgrade to 230 kV	$155 M $14 M	$98 M $5 M	46 + 35 114	$1.08 M/MW $0.63 M/MW

The 115 kV transmission line option would not be adequate to meet the needs of the Pickle Lake subsystem, with or without the Ring of Fire mining load supplied from Pickle Lake under the reference scenario forecasted load. The reference scenario forecast is considered the most likely scenario. The only scenario assessed that the 115 kV transmission line option would be adequate for the long term is the low scenario. The reference and high scenarios with and without the Ring of Fire mining load supplied from Pickle Lake would require a new 230 kV line.

Based on the following factors, the OPA recommends that a single circuit 230 kV line be developed as soon as possible:

- There is currently insufficient capacity to supply existing electrical demand; and
- A 115 kV line is insufficient to meet the reference scenario forecast demand, which is considered most likely, and therefore there is material risk in not meeting the long-term demand of the Pickle Lake subsystem with a 115 kV line; and

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[25] Description of the method for calculating costs is provided in Appendix 10.7.1 and 0. Note all costs include reactive compensation required to meet stated LMC.
[26] Requires continued supply of 24 MW of load via E1C from Ear Falls TS
[27] Generation could be developed in 2-3 years
[28] Transmission options cannot be developed before 2016
[29] 35 MW are in the Red Lake subsystem. System is voltage limited and can reach a higher LMC with additional reactive compensation. Costing does not include reactive compensation required to supply Ring of Fire.

- A 230 kV line to Pickle Lake is required to preserve the option of supplying the Ring of Fire utilizing an East-West corridor; and
- An East-West infrastructure corridor to the Ring of Fire continues to be a viable option being considered by mining developers.

Decisions made regarding a common infrastructure corridor (e.g. transportation, etc.) to the Ring of Fire should be monitored and reflected in updates to this IRRP.

7.2.1 **Discussion of Options to Meet the Needs of the Pickle Lake Subsystem**

Both generation and transmission options are considered for meeting the needs of the Pickle Lake subsystem. In developing these options, the economic connection of remote communities and maintaining supply options to the Ring of Fire are key planning factors.

The five remote communities in the Ring of Fire subsystem have been determined to be economic to connect in accordance with the conclusions of the Remote Community Connection Plan. The lowest cost transmission connection option for the five remote communities in the Ring of Fire subsystem, independent of the Ring of Fire mines, is to connect to Pickle Lake. Therefore, for the purposes of the IRRP, sufficient capacity would need to be made available in the Pickle Lake subsystem to connect up to five remote communities in the Ring of Fire subsystem as a minimum. Given the uncertainty around other infrastructure development plans for the Ring of Fire area, there is also long-term value in maintaining the option for Ring of Fire mines to connect at Pickle Lake. This connection could be realized utilizing an East-West multi-use corridor, which is being promoted by some mining developers in the area. Details are discussed in the following sections.

7.2.1.1 Reference Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

From Table 8, this scenario requires an LMC of 46 MW for the near term, and 78 MW for the medium and long term.

Generation Options

There is no existing supply of natural gas in the Pickle Lake subsystem and the OPA is not aware of any plan to expand natural gas pipeline service to Pickle Lake. However, generators fueled by Compressed Natural Gas (“CNG”) could be developed in the Pickle Lake area, as CNG could be produced and transported from the TransCanada Pipelines Limited (“TCPL” or “TransCanada”) mainline near Ignace to Pickle Lake along Highway 599 and beyond as needed. The cost of developing a CNG production facility at Ignace and transporting CNG from Ignace to Pickle Lake is significant and results in a much higher delivered cost of natural gas than in areas that are served by natural gas pipelines, such as Red Lake. To minimize generation costs in this option, it is assumed that the Pickle Lake subsystem will remain connected to Ear Falls TS and 24 MW of load in the Pickle Lake subsystem will continue to be served from Ear Falls TS.

The remaining 22 MW of LMC for the near term and 54 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 22 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total installed generation capacity of 47.5 MW would be required with a maximum unit size of 9.5 MW (i.e. 5x9.5 MW). Similarly, to make available 54 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total installed generation capacity of 76 MW would be required with a maximum unit size of 9.5 MW (i.e. 8x9.5 MW).

This arrangement of units would ensure that load could be supplied with up to two units unavailable by either forced or planned outages, while maintaining flows on E1C and at Ear Falls TS within thermal and voltage limits consistent with requirements outlined in ORTAC. Table 10 summarizes the gas generation capacity required and the increase in the Pickle Lake LMC it will provide.

Table 10: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term Reference Forecast Demand[30] [MW]	Medium and Long term Reference Forecast Demand[20] [MW]
Near term: 47.5 MW CNG Generation at Pickle Lake[31]	28.5	52.5	46	78
Medium and Long term 76 MW CNG Generation at Pickle Lake[21]	57	81	46	78

The cost (summarized in Table 11) of supplying the growth needs of the Pickle Lake subsystem with CNG fueled generation includes any additional required voltage control devices at Pickle Lake.

Table 11: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
47.5 MW CNG Generation at Pickle Lake	1-2 Years	$75 M	$158 M	$6.59 M/MW
76 MW CNG Generation at Pickle Lake[32]	1-2 Years	$132 M	$294 M	$5.44 M/MW

Generation resources in the Pickle Lake subsystem would be operated to serve local demand in the Pickle Lake subsystem in the event that load exceeds 24 MW and would likely not be dispatched in the Ontario market for supplying provincial system load due to relatively high cost of operation. At present the Ontario system has sufficient generation capacity to meet system peak and energy needs; however, by 2018 a need for additional peak capacity is forecasted. Local generation at Pickle Lake would serve demand that would otherwise be served by generation somewhere else in the system and would help to offset some of this Ontario system need.

Transmission Options

[30] Includes demand for Ring of Fire remote communities (7 MW).
[31] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.
[32] Size is cumulative.

The OPA has identified three transmission options for reinforcing the supply to the Pickle Lake area.

The transmission options are:

1. A new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker on the tap line and terminating at Crow River DS in Pickle Lake.

2. A new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker on the tap line and running to Pickle Lake terminating at Crow River DS or a new TS in the Pickle Lake area with a new 230/115 kV autotransformer.

3. A new single circuit line pre-built to 230 kV standards (230 kV structures, and hardware) and initially operated at 115 kV by connecting it to M2D on the 115 kV system near Dryden with an in-line breaker on the tap line. When additional capacity is required the line would be operated at 230 kV by re-terminating on the 230 kV system near Dryden (D26A) and a 230/115 kV autotransformer would be installed at Pickle Lake.

The 230 kV line options, Options 2 or 3, are capable of supplying the reference scenario forecasted demand for the Pickle Lake subsystem including the five remote communities in the Ring of Fire subsystem until the end of the planning period.

The 115 kV line option is capable of supplying the Pickle Lake subsystem, including the five remote communities in the Ring of Fire subsystem up to a demand of 70 MW, which is the LMC of the option. This corresponds to year 2030 for the reference scenario forecasted demand.

By opening E1C at Ear Falls TS, the Red Lake subsystem no longer supplies the Pickle Lake subsystem. Under this arrangement the capacity that was allocated to the Pickle Lake subsystem (24 MW, which corresponds to 35 MW at Ear Falls due to losses), is offloaded. In other words, a new line to Pickle Lake also provides 35 MW of incremental LMC to the Red Lake subsystem. This occurs because the new line would serve the entire load along E1C. This benefit must be accounted for in the analysis.

Details of these options have been summarized in Table 12 and Table 13 below.

Table 12: Capacity of Transmission Options

Transmission Options	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term Reference Forecast Demand[33] [MW]	Pickle Lake Subsystem Medium and Long term Reference Forecast Demand[33] [MW]
115 kV line to Pickle Lake[34]	46	35	81	70	46	78
230 kV line to Pickle Lake[35]	136	35	171	160	46	78
Pre-build 230 kV line to Pickle Lake[35] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[35]	 46 136	 35 35	 81 171	 70 160	46	78

[33] Includes demand for Ring of Fire remote communities (7 MW).
[34] Transmission options cannot be developed before 2016.
[35] Upgrade completed in 2023 when three Ring of Fire mines are forecast to be operating

To serve the forecasted electrical demand of the reference scenario to the end of the planning period, without any additional investments, transmission options 2 or 3, a new 230 kV single circuit line to Pickle Lake would be required.

Transmission Option 1, a 115 kV single circuit line to Pickle Lake is insufficient to meet the identified needs of the Pickle Lake subsystem, including connection of up to five remote communities in the Ring of Fire subsystem, for the reference forecast scenario beyond 2030. The reference forecast scenario load exceeds the LMC of a 115 kV single circuit line by 8 MW at the end of the planning period, in 2033.

The OPA recommends that the new line be operated at 230 kV from the onset. Deferring 230 kV operation to when the incremental capacity is required for load supply is not expected to incur any cost savings relative to initially operating at 230 kV. This is due to the fact that some additional voltage control equipment required for 115 kV operation would no longer be required after converting the line to 230 kV operation. This results in a stranded cost which is approximately equal to the deferral value.

Transmission Option 3 is the development of a 230 kV line that is staged to provide additional capacity with deferral of some capital cost to when and if the capacity is needed. This would be done by pre-building the line to 230 kV specifications but initially operating it at 115 kV. When additional capacity is required the line would be reterminated on the bulk 230 kV system on circuit D26A and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake. As indicated above, this option is not expected to result in any relative savings compared to Transmission Option 2.

In order to properly compare costs of transmission options (which also provide incremental capacity to the Red Lake subsystem) to generation options (which do not provide incremental capacity to the Red Lake subsystem) the unit costs consider the total incremental LMC for both the Pickle Lake and Red Lake subsystems that is made available by the option. Table 13 provides a summary of costs and timing for these options.

Table 13: Costs and Timing of Transmission Options

	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[36]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.08 M/MW $0.63 M/MW

From the above tables, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.1.2 Reference Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The Ring of Fire subsystem reference forecasted load from mines and communities is 22 MW in the near term and 29 MW in the medium and long term. Options to supply the Ring of Fire subsystem mines include on-site generation consistent with the Environmental Assessment cases for the mining developments, as well as building a new transmission line utilizing a North-South corridor and originating from either

[36] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Marathon or east of Nipigon, or utilizing an East-West corridor originating from Pickle Lake. Detailed analysis of these options is included in 7.4. As indicated in 6.2, if the Ring of Fire subsystem is supplied from Pickle Lake utilizing an East-West corridor, interdependency between the Pickle Lake subsystem and the Ring of Fire subsystem is introduced.

The following assesses the requirements for supply to the Pickle Lake subsystem under the reference forecast scenario if the mines and communities in the Ring of Fire subsystem are supplied from Pickle Lake. The corresponding LMC required for the Pickle Lake subsystem under this reference scenario is 64 MW in the near term and 100 MW in the medium and long term as indicated by the reference scenario "*Total 2*" in Table 8.

Generation Options

Generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than self-generation options at the mining sites within the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

Transmission Options

The LMC and costs for the respective transmission options are repeated below:

Table 14: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem[1] [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability[37] [MW]	Pickle Lake Subsystem Near term Reference Forecast Demand[27] [MW]	Pickle Lake Subsystem Medium and Long term Reference Forecast Demand[27] [MW]
115 kV line to Pickle Lake[38]	46	35	81	70	64	100
230 kV line to Pickle Lake[28]	136	35	171	160	64	100
Pre-build 230 kV line to Pickle Lake[28] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[39]	46 136	35 35	81 171	70 160	64	100

[37] Includes Ring of Fire subsystem.
[38] Transmission options cannot be developed before 2016.
[39] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Table 15: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake[40]	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[41]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.08 M/MW $0.63 M/MW

From the above tables, and consistent with the analysis in 7.2.1.1, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is the approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution.

This analysis reinforces the need to build a new 230 kV line to Pickle Lake, rather than a new 115 kV line.

7.2.1.3 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 43 MW for the near term, and 48 MW for the medium and long term as indicated by the low scenario "*Total 1*" in Table 8.

[40] Sufficient for near term, insufficient for medium to long term.
[41] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Sensitivity Analysis for Generation Options

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

The remaining 19 MW of LMC for the near term and 24 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 19 MW or 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 38 MW and 47.5 MW would be required, respectively, with a maximum unit size of 9.5 MW (i.e. 4x9.5 MW and 5x9.5 MW).

Table 16: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term Low Forecast Demand[42] [MW]	Medium and Long term Low Forecast Demand[32] [MW]
Near term: 38 MW CNG Generation at Pickle Lake[43]	19	43	43	48
Medium and Long term 47.5 MW CNG Generation at Pickle Lake[33]	28.5	52.5	43	48

Table 17: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
38 MW CNG Generation at Pickle Lake	1-2 Years	\$57 M	\$131 M	\$6.89 M/MW
47.5 MW CNG Generation at Pickle Lake	1-2 Years	\$75 M	\$158 M	\$6.59 M/MW

[42] Includes demand for Ring of Fire remote communities (7 MW).
[43] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

Based on the low forecast demand scenario, the initial near-term generation option does not change. However, less capacity is needed to meet the medium- and long-term needs compared to the reference scenario.

Sensitivity Analysis for Transmission Options

Under the low forecast scenario, the LMC required for the Pickle Lake subsystem is 43 MW in the near term and 48 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 43 MW in the near term and 48 MW in the medium and long term, a new line to Pickle Lake at 115 kV would be required as a minimum and would be the most economic. It should be noted that the low scenario forecast is the only scenario that the 115 kV line option is feasible; the 115 kV line option is not feasible for all other demand scenarios.

Table 18: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term Low Forecast Demand[44] [MW]	Pickle Lake Subsystem Medium and Long term Low Forecast Demand[34] [MW]
115 kV line to Pickle Lake[45]	46	35	81	70	37	41
230 kV line to Pickle Lake[35]	136	35	171	160	37	41
Pre-build 230 kV line to Pickle Lake[35] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[46]	46 136	35 35	81 171	70 160	37	41

[44] Includes demand for Ring of Fire remote communities (7 MW).
[45] Transmission options cannot be developed before 2016.
[46] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Table 19: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	3-5 Years	$126 M	$80 M	$1.31 M/MW
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$2.12 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV[47]	3-5 Years	$155 M	$98 M	$1.85 M/MW

7.2.1.4 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The low scenario does not include any additional load within the planning period from the Ring of Fire area mines compared to 7.2.1.3 and therefore this scenario is identical to 7.2.1.3 and not considered further.

7.2.1.5 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 48 MW for the near term, and 90 MW for the medium and long term as indicated by the high scenario "*Total 1*" in Table 8.

Sensitivity Analysis for Generation Options

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

[47] Stage 2 would not be required for the low forecast scenario without the Ring of Fire

The remaining 24 MW of LMC for the near term and 66 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 47.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 5x9.5 MW). To make available 66 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 85.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 9x9.5 MW).

Table 20: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term High Forecast Demand[48] [MW]	Medium and Long term High Forecast Demand[38] [MW]
Near term: 47.5 MW CNG Generation at Pickle Lake[49]	28.5	52.5	48	90
Medium and Long term: 85.5 MW CNG Generation at Pickle Lake[39]	66.5	90.5	48	90

Table 21: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
47.5 MW CNG Generation at Pickle Lake	1-2 Years	$75 M	$158 M	$6.59 M/MW
85.5 MW CNG Generation at Pickle Lake	1-2 Years	$140 M	$317 M	$4.80 M/MW

[48] Includes demand for Ring of Fire remote communities (7 MW).
[49] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

Sensitivity Analysis for Transmission Options

Under the high forecast scenario, the LMC required for the Pickle Lake subsystem is 48 MW in the near term and 90 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 48 MW in the near term and 90 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required.

Table 22: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term High Forecast Demand[50] [MW]	Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW]
115 kV line to Pickle Lake[51]	46	35	81	70	48	90
230 kV line to Pickle Lake[41]	136	35	171	160	48	90
Pre-build 230 kV line to Pickle Lake[41] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[52]	46 136	35 35	81 171	70 160	48	90

[50] Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem

[51] Transmission options cannot be developed before 2016

[52] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Table 23: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$180 M	$114 M	$1.20 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[53]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.29 M/MW $0.25 M/MW

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is about the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.1.6 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

Under the high scenario forecasted load, the LMC required is 66 MW for the near term, and 156 MW for the medium and long term as indicated by the high scenario "*Total 2*" in Table 8.

[53] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Sensitivity Analysis for Generation Options

Consistent with the reference scenario analysis, generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than generation options from the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

Sensitivity Analysis for Transmission Options

In order to supply 66 MW in the near term and 156 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required. This may be achieved by either Transmission Option 2 or Option 3.

Table 24: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term High Forecast Demand[1] [MW]	Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW]
115 kV line to Pickle Lake[2]	46	35	81	70	66	156
230 kV line to Pickle Lake[2]	136	35	171	160	66	156
Pre-build 230 kV line to Pickle Lake[2] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[3]	46 136	35 35	81 171	70 160	66	156

(1) Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem
(2) Transmission options cannot be developed before 2016
(3) Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Table 25: Costs and Timing of Transmission Options

Options	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$180 M	$114 M	$1.20 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[54]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.29 M/MW $0.25 M/MW

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need, and is only marginally sufficient to meet the near term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium-and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.2 **Pickle Lake Subsystem Recommended Solutions**

The OPA recommends that a new 230 kV single circuit line to Pickle Lake be built as soon as possible in order to meet the needs of the Pickle Lake subsystem. Building the new line to 230 kV standards is the most economic option to meet the reference forecast scenario, which is regarded as the most-likely scenario, and mitigates the long-term risk associated with higher forecasted demand scenarios and maintains the flexibility to supply the Ring of Fire mining development from Pickle Lake. The OPA also recommends that circuit E1C be opened at Ear Falls as an operational measure when

[54] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

the local system is capacity-constrained. This operational measure maximizes the capability of the transmission system in the area, resulting in incremental LMC to the Red Lake subsystem. The capacity constraint is expected to occur during high demand coincident with drought hydroelectric conditions.

It is recommended that development work on a new 230 kV single circuit line to Pickle Lake is completed as soon as possible. The OPA understands that preliminary development work has been started by two First Nations-owned transmission development companies. This work was initiated after the project was identified as a priority transmission project in the Government of Ontario’s 2010 and 2013 Long-Term Energy Plans, and was identified for inclusion in future power system plans in the Minister of Energy’s 2011 SMD to the OPA.

Implementation of the new line to Pickle Lake continues to be supported by the OPA. The OPA is following the development process for the two development companies closely. The OPA expresses urgency in the need for a new 230 kV single circuit line to Pickle Lake and will support this project to obtain the necessary approvals as soon as possible.

7.3 Summary of Recommended and Assessed Options for Meeting Red Lake Subsystem Needs

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C open at Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA’s forecast scenarios, beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and Ontario Power Generation ("OPG"), with assistance from the OPA, negotiate a new contract for amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Table 62 in Appendix 10.6 outlines the cash-flows associated with the circuit upgrades including the station costs being referred to above.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This analysis will consider an updated forecast. The economics of additional gas-fired generation compared to a new transmission line will depend on the amount of load that materializes – gas generation is scalable, while transmission has greater economies of scale if enough demand is present for a sufficient level of utilization. Re-evaluating options in future planning cycles is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

The following section summarizes the analysis and comparison of options.

As mentioned previously, the Red Lake subsystem is currently supplied by the 115 kV line E4D from Dryden TS as well as local run of river hydroelectric generation around Ear Falls. At present the subsystem has reached its LMC. Therefore, forecasted near term growth and medium and long term growth cannot be met by the existing system and other supply options are required. Identified needs for the Red Lake subsystem are summarized in Table 26, below.

Table 26: Needs for Red Lake Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	Reference	High
Near term (2014-2018)	• Supply of mining and community demand in the Red Lake subsystem	91	91	91
	Total Near term	***91***	***91***	***91***
Medium and long term (2019-2033)	• Supply of mining and community demand in the Red Lake subsystem	100	109	136
	Total Medium and Long term	***100***	***109***	***136***

The following near term generation and transmission options have been identified for meeting these needs.

Table 27: Summary of Options to Meet the Near-term Needs of the Red Lake Subsystem

Options to Meet Near-term Needs	Capital Cost	PV Cost	Incremental Load Meeting Capability	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	\$89 M	\$51 M	30 MW	\$1.94 M/MW
Off Load E1C to New Line to Pickle Lake[55]	\$66 M	\$42 M	35 MW	
Upgrade E4D and E2R	\$16 M	\$11 M	34 MW	\$1.11 M/MW[56]
Off Load E1C to New Line to Pickle Lake	\$66 M	\$42 M	35 MW	

The OPA recommends upgrading E4D and E2R, as this option has the lowest NPV cost for meeting the near-term needs of the Red Lake subsystem. This option also has the shortest lead time and the highest incremental capacity.

[55] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[56] Note that utilized capacity is 30 MW in the near term.

Table 28: Summary of Options to Meet the Medium- and Long-Term Needs of the Red Lake Subsystem

Options to Meet Medium- and Long-Term Needs	Capital Cost	PV Cost[57]	Incremental Load Meeting Capability	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)[58]	$95 M	$6 M	30 MW	$0.20 M/MW
Ear Falls and Red Lake Gas Generation (60 MW)	$153 M	$8 M	60 MW	$0.13 M/MW
Install Voltage Compensation at Ear Falls and Red Lake (130 MW)	$9 M	$1 M	21 MW	$0.05 M/MW
New 115 kV line to Ear Falls (160 MW)	$91 M	$10 M	30 MW	$0.34 M/MW
New 115 kV line to Ear Falls (190 MW)	$108 M	$12 M	60 MW	$0.20 M/MW
New 230 kV line to Ear Falls (190 MW)	$132 M	$15 M	60 MW	$0.25 M/MW

Once the upgrades to E4D and E2R are complete and the new line to Pickle Lake is in service, the Red Lake subsystem will have an LMC of 130 MW, which is sufficient to meet the supply needs of the Red Lake subsystem for the long term.

Costs do not need to be incurred at this time for additional enhancements for the Red Lake subsystem beyond E4D and E2R upgrades. Under the low scenario and reference scenario (which is considered most likely) no incremental LMC is required beyond 130 MW. Only under the high scenario is incremental LMC forecasted to be required in 2030. The lead times for the long-term incremental options allow for re-evaluation of the demand forecast and options in future planning cycles. Future planning cycles will contain more certainty in the demand forecast as mines and related development materialize. The next planning cycle for the North of Dryden sub-region is between 1-5

[57] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until about 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.
[58] Same as the near term option, with install date of 2030 and therefore cannot be combined with the near term option.

years, as per the OEB-sanctioned regional planning process. The prudent course of action for the long term is monitoring load growth and re-evaluating in a timely manner.

7.3.1 Discussion of Options to Meet the Needs of the Red Lake Subsystem

Both generation and transmission options are considered for meeting the needs of the Red Lake subsystem.

The following sub-sections will outline the evaluation of various integrated options to meet the near-term and medium-to long-term needs of the Red Lake subsystem for the reference, low, and high load forecast scenarios.

7.3.1.1 Reference Scenario Options Analysis for Red Lake Subsystem

Under the reference scenario, the LMC required is 91 MW for the near term, and 109 MW for the medium and long term as indicated by the reference scenario in Table 26. The existing LMC for the Red Lake subsystem is 61 MW, which is not sufficient.

In establishing the need for incremental LMC for the Red Lake subsystem, it is assumed that, consistent with the recommendations for addressing supply needs for the Pickle Lake subsystem, a new line to Pickle Lake will be implemented and circuit E1C will be operated open at Ear Falls SS. Opening circuit E1C from Ear Falls SS relieves circuit E4D of 35 MW.

Generation Options

At Red Lake, there is a limited supply of natural gas on the existing Union Gas pipeline. This pipeline was extended to serve the needs of an industrial customer at Red Lake and the Town of Red Lake. Based on information provided by the industrial customer, there is sufficient pipeline capacity to increase the LMC by 30 MW from gas-fired generation at Red Lake.

The OPA studied the costs and benefits of implementing gas fired generation to provide incremental LMC in the Red Lake subsystem. The generators could operate both as a local area resource and as a system resource to support growth in northwest Ontario, by reducing loading on the bulk transmission system at Dryden TS. Gas generators in the Red Lake subsystem would be expected to operate for local area needs primarily during periods when run of river hydroelectric generation near Ear Falls is low and when the demand in the area is high.

Due to the availability of gas on the pipeline and the distribution of load in the Red Lake subsystem, gas generation at Red Lake would increase the LMC of the Red Lake subsystem by 30 MW. Table 29 summarizes the capability and Table 30 summarizes the cost and timing associated with the gas generation option.

Table 29: Capacity for Generation Options

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term Reference Forecast Demand [MW]</th><th>Medium and Long term Reference Forecast Demand [MW]</th></tr>
<tr><td rowspan="2">Red Lake Gas Generation (30 MW)
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>30 MW</td><td>91 MW</td><td rowspan="2">91</td><td rowspan="2">109</td></tr>
<tr><td>35 MW</td><td>126 MW</td></tr>
</table>

Table 30: Costs and Timing for Generation Options

<table>
<tr><th>Option</th><th>Time to Complete</th><th>Capital Cost</th><th>Total PV During Planning Period</th><th>PV Unit Cost of Utilized Capacity</th></tr>
<tr><td>Red Lake Gas Generation (30 MW)</td><td>2 Years</td><td>$89 M</td><td>$51 M</td><td rowspan="2">$1.94 M/MW</td></tr>
<tr><td>Transfer of E1C load to new line to Pickle Lake[59]</td><td>3-5 Years</td><td>$66 M</td><td>$42 M</td></tr>
</table>

It is important to note that the transfer of Pickle Lake load from E1C to relieve the Red Lake subsystem can be made once a new line to Pickle Lake is in service. This again

[59] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

emphasizes the urgent need to implement the new line to Pickle Lake, as it has broader benefits for incremental LMC for the Red Lake subsystem.

Transmission Options

Hydro One Networks Inc. owns and operates transmission lines E4D and E2R and has confirmed that they can be upgraded from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. This upgrade increases the LMC of the Red Lake subsystem by 34 MW. To enable this higher transmission capability, additional voltage control would also be required at Ear Falls TS. Hydro One has indicated that upgrading E4D and E2R and the installation of the required voltage control devices would take two years and could be completed within the near-term period.

Table 31: Capacity of Transmission Option

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Reference Forecast Demand [MW]	Medium and Long term Reference Forecast Demand [MW]
Near-term Option				
Upgrade E4D and E2R and Transfer of Pickle Lake load to new line to Pickle Lake	34	95	91	109
	35	130		

Upgrading the transfer capability of E4D and E2R and installation of the required amount of voltage control is the recommended solution for the Red Lake subsystem. This option satisfies the reference scenario forecasted demand at the least cost. When E4D and E2R are upgraded and the required amount of voltage control is installed at Ear Falls TS, there will be 95 MW of capacity at Ear Falls TS to serve load in the Red Lake subsystem and 35 MW available to continue to serve the Pickle Lake subsystem. Once a new line to Pickle Lake is implemented and circuit E1C is operated open at Ear Falls SS, an additional 35 MW of LMC is provided to the Red Lake subsystem because currently the Pickle Lake subsystem currently requires 35 MW of supply from Ear Falls to serve 24 MW of load (due to losses). This brings the total LMC for the Red Lake subsystem to 130 MW. The combination of the line upgrades to E4D and E2R as well as a new line to Pickle Lake is expected provide enough LMC for the Red Lake subsystem until the end of the study horizon for the reference forecast scenario.

It should be noted that the incremental LMC of 35 MW provided to the Red Lake subsystem from transferring E1C load to the new line to Pickle Lake requires the E4D and E2R upgrades to be completed. Without the upgrades, E2R would limit the supply into Red Lake because E2R is not relieved from transferring E1C load (E1C transfer only relieves E4D).

This again emphasizes the urgent need to implement both the upgrades to circuits E4D and E2R, as well as the new line to Pickle Lake, as combined these solutions provide a significant increase in LMC for the Red Lake subsystem.

Table 32: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[60]	PV During Planning Period	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	$16 M	$11 M	$1.11 M/MW
Transfer of E1C load to new line to Pickle Lake[61]	3-5 years	$66 M	$42 M	

Based on the above analysis of Generation and Transmission Options for the reference scenario, the upgrading of circuits E4D and E2R in combination with the relief provided by transferring E1C demand to a new line to Pickle Lake is the most economic solution to meet the needs of the Red Lake area. This solution would be sufficient to meet the electrical demand in the Red Lake subsystem until beyond the planning period.

[60] Capital cost does not include the capital cost for new system generation
[61] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

The IESO recently completed SIAs for three customers in the Red Lake subsystem that are interested in increasing their demand on the system. Upgrading of E4D and E2R was also identified by the IESO as the preferred solution to meet the load increase requests. The IESO's analysis is consistent with the OPA's findings.

7.3.1.2 Low Scenario Options Analysis for Red Lake Subsystem

Under the low scenario, the LMC required is 91 MW for the near term, and 100 MW for the medium and long term as indicated by the low scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Red Lake subsystem under the low scenario, the generation option assessed for the reference scenario remains unchanged and is therefore not sensitive to the low scenario demand. A summary of capacity and costs are repeated in the following tables for convenience:

Table 33: Capacity for Generation Options

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Low Forecast Demand [MW]	Medium and Long term Low Forecast Demand [MW]
Red Lake Gas Generation (30 MW) and Transfer of Pickle Lake load to new line to Pickle Lake	30 MW	91 MW	91	100
	35 MW	126 MW		

Table 34: Costs and Timing for Generation Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	2 Years	$89 M	$51 M	$2.38 M/MW
Transfer of E1C load to new line to Pickle Lake[62]	3-5 Years	$66 M	$42 M	

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Red Lake subsystem under the low scenario, the transmission options assessed for the reference scenario remain unchanged and are therefore not sensitive to the low scenario demand. A summary of capacity and costs are repeated in the following tables for convenience:

Table 35: Capacity of Transmission Option

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Low Forecast Demand [MW]	Medium and Long term Low Forecast Demand [MW]
Near-term Option				
Upgrade E4D and E2R and Transfer of Pickle Lake load to new line to Pickle Lake	34	95	91	100
	35	130		

Table 36: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[63]	PV During Planning Period	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	$16 M	$11 M	$1.36 M/MW
Transfer of E1C load to new line to Pickle Lake[64]	3-5 years	$66 M	$42 M	

[62] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[63] Capital cost does not include the capital cost for new system generation
[64] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

7.3.1.3 High Scenario Options Analysis for Red Lake Subsystem

Under the high scenario, the LMC required is 91 MW for the near term, and 136 MW for the medium and long term as indicated by the high scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Red Lake subsystem under the high scenario, additional gas generation at Ear Falls or Red Lake would be required in the long term compared to the reference scenario. However, it should be noted that based on information from the existing industrial customer gas pipeline capacity is not available to support gas-fired generation beyond 30 MW.

The option of incremental gas generation has been assessed assuming that industrial customers may require additional natural gas supply to serve their industrial processes.

A summary of capacity and costs are summarized in the following tables:

Table 37: Capacity for Generation Options

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term High Forecast Demand [MW]</th><th>Medium and Long term High Forecast Demand [MW]</th></tr>
<tr><td rowspan="2">Red Lake Gas Generation (30 MW)

and

Transfer of Pickle Lake load to new line to Pickle Lake</td><td>30</td><td>91</td><td rowspan="2">91</td><td rowspan="2">136</td></tr>
<tr><td>35</td><td>126</td></tr>
<tr><td colspan="5">Incremental Long term Options</td></tr>
</table>

Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[65]	30	156	91	136

Table 38: Costs and Timing for Generation Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	2 Years	$89 M	$51 M	$1.36 M/MW
Transfer of E1C load to new line to Pickle Lake[66]	3-5 Years	$66 M	$42 M	
Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[67]	TBD[1]	$95 M[68]	$6 M[69]	$1.00 M/MW

From the above, the option of 30 MW of gas-fired generation at Red Lake using existing pipeline capacity in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake would result in an LMC of 126 MW for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2027 under the high scenario.

The sensitivity analysis does not impact the decisions that are required during this planning cycle. Demand forecasts and long term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Red Lake subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged and

[65] Contingent on new gas pipeline to serve new electricity and gas customers
[66] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[67] Contingent on new gas pipeline to serve new electricity and gas customers
[68] Capital Cost does not include pipeline costs. It is assumed that if the pipeline was needed anyway, there would be no incremental pipeline costs to incorporate generation
[69] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2026 at earliest, and therefore only 3 years of costs discounted over 13 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

are therefore not sensitive to the high scenario demand. A summary of capacity and costs are repeated in the following tables:

Table 39: Capacity of Transmission Option

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term High Forecast Demand [MW]	Medium and Long term High Forecast Demand [MW]
Near-term Option				
Upgrade E4D and E2R	34	95	91	136
and Transfer of Pickle Lake load to new line to Pickle Lake	35	130		
Incremental Long-term Options				
New 115 kV line to Ear Falls (160 MW LMC)	30	160	91	136
New 115 kV line to Ear Falls (190 MW LMC)	60	190	91	136
New 230 kV line to Ear Falls (190 MW LMC)	60	190	91	136

Table 40: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[70]	PV During Planning Period[71]	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	\$16 M	\$11 M	\$0.78 M/MW
Transfer of Pickle Lake load to new Line at Pickle Lake[72]	3-5 years	\$66 M	\$42 M	
New 115 kV line to Ear Falls (160 MW LMC)	4-7 years	\$91 M	\$10 M	\$1.72 M/MW
New 115 kV line to Ear Falls (190 MW LMC)	4-7 years	\$108 M	\$12 M	\$2.04 M/MW
New 230 kV line to Ear Falls (190 MW LMC)	4-7 years	\$132 M	\$15 M	\$2.5 M/MW

[70] Capital cost does not include the capital cost for new system generation
[71] Present Value costs for long-term options (i.e. all except E4D and E2R upgrades, and Transfer of Pickle Lake load to new Line at Pickle Lake) consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.
[72] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

From the above, upgrading lines E4D and E2R (Dryden to Red Lake) in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake, an LMC of 130 MW would result for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2030 under the high scenario forecasted demand, but not under the reference scenario (which is considered most likely). Incremental transmission options are available if forecasted demand consistent with, or greater than, the high scenario is realized. This is not expected to occur until 2030 under the high scenario and beyond the planning period for the reference scenario. A recommendation for incremental enhancements in addition to the line upgrades and the new line to Pickle Lake does not need to be made at this time. Demand forecasts and long-term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

7.3.2 **Cost Saving Opportunities Utilizing Existing Facilities**

OPG provided information to the OPA on voltage control capabilities of the generating units at Manitou Falls as part of their comments on the Draft North of Dryden IRRP. This information was submitted in writing on November 8th, 2013. Part of this submission indicated that the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power for voltage control during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Total station costs for upgrading E4D and E2R are referenced in Table 62 of Appendix 10.6.

OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is of benefit to the rate payer.

7.3.3 **Red Lake Subsystem Recommended Solutions**

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C normally open at

Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA's forecast scenarios; beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

7.4 Summary of Options to Meet Ring of Fire Subsystem Needs

The Ring of Fire subsystem is a large geographic area on the edge of the Hudson Bay Lowlands approximately 350 km north of Long Lac and approximately 300 km east of Pickle Lake. There are five remote First Nations ("FN") communities in the area (Eabametoong FN, Neskantaga FN, Marten Falls FN, Nibinamik FN and Webequie FN) and a proposed mine development area called the Ring of Fire, where a number of companies are developing mining claims. At present the five remote First Nations communities are supplied electricity by local diesel generators.

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem, including the connection of the remote communities, be coordinated with other infrastructure being investigated or planned, such as transportation corridors to the communities and potential mining development. Mining development companies have indicated different transportation corridor preferences for the Ring of Fire. The OPA understands that a transportation corridor may be developed in an East-West orientation from the Pickle Lake area, or in a North-South orientation from the Nakina area. Transmission options may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or a point east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The OPA has included transmission supply options for the Ring of Fire subsystem that are consistent with these general corridor orientations identified by mining proponents. A shared East-West or North-South transmission corridor, in alignment with a transportation corridor, could be a way to reduce overall cost and environmental impact. Mining development companies have also indicated self-generation as their electrical supply base case in their EA documentation. Consistent with the EA documentation of mining development companies, the OPA has considered self-generation as a possible option for the forecasted mining load in the Ring of Fire subsystem. The decision as to whether the mining load in the Ring of Fire subsystem is supplied by transmission or generation will ultimately lie with the mining companies as they will be the beneficiaries of a direct transmission supply. The OPA has already indicated in the Remote Community Connection plan that there is a business case for connecting the five remote communities in the vicinity of the Ring of Fire on their own merit, without the connection of the mining development. The connection of the mining development with the five remote communities creates a stronger business case for the connection of the remote communities. The OPA will continue to support the economic connection of remote communities.

The relative economics of generation versus transmission to supply mining load in the Ring of Fire subsystem depends on the amount of electrical demand that materializes. The reason for this is because transmission is generally more economic for relatively large electrical demand, while generation is scalable and generally more economic for lower levels of electrical demand. Details of the various options are explained further later in this section.

The OPA also recognizes that there may be potential for further utilization of a North-South transmission supply to the Ring of Fire subsystem through integration with supplying new growth in the Greenstone area. The detailed needs and supply options specific for new growth in the Greenstone area will be assessed as part of the Greenstone-Marathon IRRP, which may be used to supplement the findings in this IRRP.

The needs identified for the Ring of Fire subsystem are to connect the five remote communities to the provincial transmission system and to supply the potential future mines. The connection of the five remote communities cannot be completed until at least 2018, as indicated in the Remote Community Connection Report. Also, mines at the Ring of Fire are not expected to start up until 2017 at the earliest. A summary of the needs is provided in Table 41.

Table 41: Needs for the Ring of Fire Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	Reference	High
Near term (2014-2018)	• Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems	4	22	22
	Total Near term	***4***	***22***	***22***
Medium and long term (2019-2033)	• Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems	7	29	73
	Total Medium and Long term	***7***	***29***	***73***

An assessment developed for the Remote Community Connection Plan determined that up to five remote First Nation communities in the subsystem are economic to connect to the grid (see Appendices 11.2 and 11.4). As a result, all options identified for this subsystem include the connection of the five remote communities included in this subsystem.

Options to meet these requirements include:

- Connection of mines and remote communities to the transmission system; or
- Connection of the remote communities and on-site generation fueled by diesel or natural gas for the mines.

Transmission supply options being considered for the Ring of Fire subsystem include a new supply from Pickle Lake, a point east of Nipigon, or Marathon. These options were developed with the understanding that both East-West and North-South transportation corridors are being considered and linear corridor planning with electricity may provide greater economic efficiencies and reduce environmental impacts. It should also be noted that 230 kV supply to Pickle Lake is the minimum technical requirement for connecting any mining load at the Ring of Fire to Pickle Lake.

Options for supply to the Ring of Fire subsystem are summarized in Table 42 below.

Table 42: Summary of Options to Meet the Medium- and Long-Term Needs of the Ring of Fire Subsystem[73]

	Capital Cost[74]	**PV Cost**	**Utilized Capacity**	**PV Unit Cost of Utilized Capacity**
Diesel Generation + Remote Connection	Low: $186 M High: $277 M	Low: $456 M High:$1,009 M	29 MW 73 MW	$15.7 M/MW $13.8 M/MW
CNG Generation + Remote Connection	Low: $240 M High: $421 M	Low: $272 M High: $480 M	29 MW 73 MW	$9.37 M/MW $6.58 M/MW

[73] Transmission options routed from Pickle Lake include a prorated portion (based on the relative amount of load that would be supplied to each party) of the cost for a new 230 kV transmission line to Pickle Lake.
[74] Description of capital costs can be found in the following tables: Generation, Table 26; Transmission, Table 27

115 kV Line from Pickle Lake to Ring of Fire	$189 M	$106 M	29 MW	$3.64 M/MW
230 kV Line from Pickle Lake to Ring of Fire	$277 M	$156 M	73 MW	$2.14 M/MW
230 kV Line from Marathon to Ring of Fire	$327 M	$175 M	73 MW	$2.40 M/MW
230 kV Line from east of Nipigon to Ring of Fire	$327 M	$175 M	73 MW	$2.40 M/MW

Options that are developed for the scenario that the Ring of Fire subsystem mining developments and remote communities are supplied from a transmission connection to the provincial power system assumes the cost for the transmission option with road access. The option for connecting only the remote communities from a transmission connection to the provincial power system assumes the cost for the transmission option without road access. Road access may be provided from the development of a multi-use corridor.

7.4.1 **Discussion of Options to Meet the Needs of the Ring of Fire Subsystem**

Currently, the electric supply of the five remote communities in the Ring of Fire subsystem is provided by local diesel generators. As discussed previously, up to five of these communities have been shown to be economic to connect to the transmission system in the Remote Community Connection Plan. Hence, for the purpose of the North of Dryden IRRP, these five communities are assumed to connect to the transmission system.

Given the timelines required to obtain approvals and to design and construct transmission facilities of this scale, the OPA has assumed that transmission options for serving remote communities would not be in service until 2018 at the earliest.

7.4.1.1 Reference Scenario Options Analysis for Ring of Fire Subsystem

Under the reference scenario electrical demand forecast, the LMC required is 22 MW for the near term, and 29 MW for the medium and long term as indicated in Table 41. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

Generation Options

Two Environmental Assessment Terms of Reference published by mining developers in the Ring of Fire have included electricity supply options for on-site generation for their particular mining projects. They have identified that diesel or CNG fueled generation plants can provide sufficient capacity and energy to reliably meet their needs and can be brought into service within their mine development timelines. Assuming that a proposed all-season road would connect the Ring of Fire to the provincial highway system, the transportation of the large volumes of fuel required to operate on-site generation of this scale would be enabled.

As mentioned earlier, the five remote communities in the Ring of Fire subsystem have been identified as economic to connect to the transmission system at Pickle Lake. Should the Ring of Fire mines choose the self–generation option for their electricity needs, it is assumed that the remote communities will connect to Pickle Lake through a separate remote community connection project. This option is discussed in detail in the Remote Community Connection Plan. The cost of serving the remote communities by transmission and the Ring of Fire area mines with on-site generation are considered together as an integrated option for serving the Ring of Fire subsystem.

The OPA evaluated the feasibility and relative economics of various on-site generation options to supply the mining load. Findings indicated that reciprocating engines fueled either by diesel or natural gas could power future mines at the Ring of Fire, which is consistent with the respective EA Terms of Reference of developers. These units are available in a large range of sizes which allows for capacity to be scaled to meet a wide range of needs for individual mines initially and over time. Mine developers at the Ring of Fire have plans for transportation systems that would connect the Ring of Fire to the provincial transportation network, by either road or rail. One of these options is an all-season road from the Ring of Fire to the railway near Nakina. In order to develop cost estimates for this regional plan it is assumed that fuel would be transported to the Ring of Fire via the provincial road network to Nakina and then from Nakina to the Ring of Fire via the proposed all-season road[75].

Supplying diesel fuel to mine sites for power generators is common practice. Diesel fuel can be purchased at a number of bulk storage facilities in northwest Ontario and transported to mine sites. CNG also appears to be feasible though there are no direct examples that the OPA could reference for remote mining applications. The OPA has leveraged available public information and worked with industry to establish a reasonable set of assumptions and inputs that were used to develop cost models for both remote diesel and CNG fueled DG. The cost of fuel transportation infrastructure (trucks and trailers) required to transport both diesel and CNG to the mine sites has been included in the cost analysis.

The infrastructure required to fuel a natural gas generation facility at the Ring of Fire would include a compression station located along the TCPL mainline with road access to the proposed all-season road to the Ring of Fire beginning near Nakina. Due to the complexities and permitting required to build a CNG storage facility at the mine site, the OPA understands that no CNG storage facilities are planned for the mine sites and that fuel would be delivered on a just in time basis, with allowance for only a few trailers to be kept on site. Each trailer stores approximately 2 hours supply of fuel.

While the process is not substantially different from the transport and use of diesel, there are more steps and facilities required to compress, transport and decompress the gas before it can be used. Without significant on-site storage facilities, natural gas transportation logistics will be more challenging particularly during inclement weather when the all-season road may be closed for extended periods. To account for such challenges, it is likely that the generators will have to be capable of using both diesel and natural gas. Mines will have large scale diesel storage on site to fuel their vehicles and heavy equipment which could be used to fuel the generators when natural gas

[75] The OPA does not have expertise in transportation planning; this assumption is solely for developing cost estimates for generation OM&A and does not indicate a preference of the OPA.

supply is interrupted. The OPA has also discussed the results of its CNG cost model with industry to ensure the findings are reasonable.

Liquefied natural gas ("LNG") may also be a feasible option to fuel generators. However, it is not clear what minimum production volume is required to establish a natural gas liquefaction facility in northwest Ontario or what the economics of such facilities would be. As a result, the OPA does not have sufficient information to assess either the feasibility or the economics of LNG at this time.

Table 43: Generation Options at the Ring of Fire Mines

Options for Mining Load	Mining Generation [MW]	Near term Reference Forecast Demand (Mines Only) [MW]	Medium and Long term Reference Forecast Demand (Mines Only) [MW]
Diesel Generation	22	18	22
CNG Generation	22		

From the above, in order to meet the reference scenario demand for the Ring of Fire mining load, up to 22 MW of diesel or CNG generation are considered.

The costs for supplying the forecasted Ring of Fire subsystem mining load by either 22 MW of diesel or CNG generation at the Ring of Fire mines are summarized in Table 44.

Table 44: Generation Options at the Ring of Fire Mines

Options for Mining Load	Mining Generation [MW]	Initial Capital Cost	Average Annual Fuel and O&M	Total PV
Diesel Generation	22	$72 M	$39 M	$393 M
CNG Generation	22	$127 M	$20 M	$209 M

As discussed above, the integrated options for serving the needs of the remote communities and the mines in the Ring of Fire subsystem includes a transmission connection option to serve the five remote communities from Pickle Lake in the case where the Ring of Fire mines opt for self-generation. This option would consist of a 115 kV transmission line from Pickle Lake to an end point near Webequie FN, passing near Neskantaga FN. Transformer stations to serve the communities would be sited near Neskantaga FN and at the end of the line near Webequie FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would be connected via distribution lines and stations to the transformer station near Neskantaga FN, while Webequie FN and Nibinamik FN would be connected by distribution lines and stations to the transformer station near Webequie FN. Figure 36 in Appendix 11.4 shows this planned connection system for the five remote communities.

The OPA has estimated the cost of connecting the five remote communities in this subsystem to be $64 million, consistent with the 2014 Remote Community Connection Plan. The costs of the integrated options for mine site generation and transmission connection of remote communities are summarized in Table 45.

Table 45 Integrated Options for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake

Integrated Options	PV of Mine Site Generation	PV Remote Connection	Total PV of Integrated Option
Diesel Generation + Remote Connection	$393 M	$62 M	$456M
CNG Generation + Remote Connection	$209 M	$62 M	$272 M

Therefore, in order to supply the entire need for the Ring of Fire subsystem – connection of remote communities and generation supply to mines – a new 115 kV connection for remote communities and 22 MW of generation would be required and would total $273-$457 M, depending on fuel.

Transmission Options

Transmission options for supplying the five remote communities and mining load at the Ring of Fire together include the following:

1. East-West corridor
    a. A new 115 kV single circuit line from Crow River DS or a new station at Pickle Lake to the Ring of Fire
    b. A new 230 kV single circuit line from a new 230/115 kV station at Pickle Lake to the Ring of Fire, and new 230/115 kV TS near Neskantaga FN
2. North-South corridor
    a. A 230 kV single circuit line from Marathon TS to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN
    b. A 230 kV single circuit line from east of Nipigon to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN

The LMC of these options are summarized in Table 46 below

Table 46: Capacity of Transmission Options

Options	Ring of Fire Subsystem Load Meeting Capability [MW]	Ring of Fire Subsystem Near term Reference Forecast Demand [MW]	Ring of Fire Subsystem Medium and Long term Reference Forecast Demand [MW]
East-West corridor			
115 kV line from Pickle Lake	67	22	29
230 kV line from Pickle Lake	78	22	29
North-South corridor			

230 kV line from Marathon TS	78	22	29
230 kV line from east of Nipigon	78	22	29

Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 67 MW of load at the Ring of Fire (60 MW of mining load plus 7 MW of remote community load). Figure 36 in Appendix 11.4 shows a potential configuration of the North of Dryden system with a 115 kV connection to the Ring of Fire from Pickle Lake. This would be sufficient and would be the least-cost option to supply the reference scenario forecasted demand.

It is not economic under the reference scenario forecasted demand to supply the Ring of Fire subsystem by a 230 kV transmission line.

If mining and remote community load exceeds 67 MW a new 115 kV supply would no longer be sufficient and a 230 kV connection to the Ontario transmission system is required for the Ring of Fire subsystem.

The North-South options will be assessed in further detail in the Greenstone-Marathon IRRP by considering possible economic synergies with potential load growth in the Greenstone area.

As mentioned in Section 7.4.1, the five remote communities in the Ring of Fire subsystem have been identified in the Remote Community Connection Plan as being economic to connect on their own. It is therefore assumed that if the Ring of Fire mines do not connect to the grid, then the five remote communities will continue to pursue a connection to the transmission system at Pickle Lake. The lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN.

A summary of the cost and capabilities of these options is provided in Table 47.

Table 47: Capacity and Costs of Transmission Options

Options	Capital Cost	Prorated Capital of Line to Pickle Lake	Total Capital	Total PV During Planning Period
Remote Community Only Connection from Pickle Lake (115 kV)	$101 M	$13 M	$114 M	$62 M
New 115 kV line from Pickle Lake to Ring of Fire	$146 M	$44 M	$189 M	$106 M
New 230 kV line from Pickle Lake to Ring of Fire	$196 M	$35 M	$231 M	$127 M
New 230 kV Line from Marathon to Ring of Fire	$327 M	N/A	$327 M	$175 M
New 230 kV Line from east of Nipigon to Ring of Fire	$327 M	N/A	$327 M	$175 M

The cost responsibility for the new line to Pickle Lake and any connection line to the Ring of Fire shared by mines and remote communities would be determined through commercial agreements and/or through the OEB's Leave to Construct application process.

7.4.1.2 Low Scenario Options Analysis for Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 4 MW for the near term, and 7 MW for the medium and long term as indicated by the low scenario in Table 41. This scenario corresponds to the load associated with only the five remote communities in the Ring of Fire subsystem.

Therefore, under this scenario, only the connection of the five remote communities is considered. As indicated in the previous section, the lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN. This is expected to cost $115 M net-present value over the planning period.

Details are included in the Remote Community Connection Report. This scenario does not require any additional consideration.

7.4.1.3 High Scenario Options Analysis for Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 22 MW for the near term, and 73 MW for the medium and long term as indicated by the high scenario in Table 41. Of the 73 MW, 66 MW is mining load and 7 MW is community load. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the high generation option would be required. The tables outlining the generation options are repeated for convenience:

Table 48: Generation Options at the Ring of Fire

Options for Mining Load	Mining Generation [MW]	Initial Capital Cost	Average Annual Fuel and O&M	Total PV
Diesel Generation	71	$163 M	$102 M	$946 M
CNG Generation	71	$307 M	$46 M	$418 M

Table 49: Integrated Option for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake

Integrated Options	PV of Mine Site Generation	PV Remote Connection	Total PV of Integrated Option
Diesel Generation + Remote Connection	$946 M	$62 M	$1,009 M
CNG Generation + Remote Connection	$393 M	$62 M	$456 M

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged. A summary of capacity and costs are repeated in the following tables for convenience:

Table 50: Capacity of Transmission Options

Options	Ring of Fire Subsystem Load Meeting Capability [MW]	Ring of Fire Subsystem Near term High Forecast Demand [MW]	Ring of Fire Subsystem Medium and Long term High Forecast Demand [MW]
East-West corridor			
115 kV line from Pickle Lake	67	22	73
230 kV line from Pickle Lake	78	22	73
North-South corridor			
230 kV line from Marathon TS	78	22	73
230 kV line from east of Nipigon	78	22	73

Table 51: Capacity and Costs of Transmission Options

Options	Capital Cost	Prorated Capital of Line to Pickle Lake	Total Capital	Total PV During Planning Period
Remote Community Only Connection from Pickle Lake (115 kV)	$101 M	$13 M	$114 M	$62 M
New 115 kV line from Pickle Lake to Ring of Fire	Not Technically Feasible for medium to long term			
New 230 kV line from Pickle Lake to Ring of Fire	$196 M	$35 M	$231 M	$127 M
New 230 kV Line from Marathon to Ring of Fire	$327 M	N/A	$327 M	$175 M
New 230 kV Line from east of Nipigon to Ring of Fire	$327 M	N/A	$327 M	$175 M

As indicated previously, a 115 kV line to the Ring of Fire subsystem could supply up to 67 MW, and a 230 kV line would be required to serve demand greater than 67 MW.

Based on the high demand scenario, a 230 kV supply to the Ring of Fire subsystem would be required. A recommendation for a specific solution is not required at this time. The magnitude and timing of the potential mining load is still very uncertain, and decisions regarding transportation infrastructure to the Ring of Fire have not yet been made. A common corridor to the Ring of Fire should consider the potential need for a transmission line.

7.4.2 **Ring of Fire Subsystem Recommendations**

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem is coordinated with other infrastructure being investigated, such as transportation. Transmission may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The lowest cost option for meeting the medium- and long-term identified needs is a transmission connection from either Pickle Lake, Marathon, or east of Nipigon to the Ring of Fire. The incremental cost of developing a transmission connection capable of serving mines and remote communities is substantially lower than the cost of generation to serve mines and separately connect the remote communities.

8 FEEDBACK FROM ENGAGEMENT AND CONSULTATION

8.1 Aboriginal Consultation

The OPA recognizes the importance of engaging with First Nation and Métis communities and carrying out the procedural aspects of Aboriginal consultation where delegated by the Crown.

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on the Draft North of Dryden IRRP. The Ministry of Energy wrote to each community on the consultation list by letter dated April 25, 2014 to provide notice of the consultation and the delegation of the OPA's role as a delegate of the Crown. The OPA then wrote to each community by letter dated May 26, 2014 to provide the dates and locations of the consultation sessions scheduled for June 2014. The letters included the OPA's commitment to cover the cost of travel and accommodation expenses associated with attending a consultation session. OPA staff then phoned each community to follow up and to answer questions about the North of Dryden IRRP consultation and provided presentation materials in advance of all sessions. The OPA sent additional invitation letters by registered mail on September 26, 2014 for the consultation session that occurred on October 16, 2014. The OPA followed up by phoning each community to ensure that leadership and/or band staff were aware of the North of Dryden consultation.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. Representatives from 15 communities attended the sessions. Two communities informed the OPA that the North of Dryden IRRP is outside their area of interest. Representatives from the Chiefs of Ontario, Grand Council Treaty 3, and Nishnawbe Aski Nation also attended the sessions but did so for informational purposes only. Notes of these sessions were prepared by the OPA and posted in the regional planning section of the OPA's website.

The OPA was in contact with the Métis Nation of Ontario ("MNO") on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO's member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

The OPA met with Red Sky Métis Independent Nation on June 19 at Red Sky's office in Thunder Bay. OPA staff delivered a presentation on the North of Dryden IRRP and answered questions posed by Red Sky's representatives.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights. Some clarifying questions were asked during the sessions, and there were some non-consultation related questions regarding electricity rates following the connection of the remote communities identified in the Remote Community Connection Plan. At this point in time, it is not yet known how the distribution service would be structured and therefore it is not possible to determine the impact to rates in a detailed manner. Rates similar to other rural distribution customers in northwestern Ontario are believed to be expected. Other general comments included:

- the need for capacity building in communities to facilitate greater participation in consultation sessions
- some communities wish to focus on project-level consultation with proponents due to the more immediate potential impacts.

8.2 Municipal Engagement

Following the publication of the Draft North of Dryden IRRP, the OPA travelled across the northwest to meet with various municipal representatives from affected municipalities. The following summarizes these meetings:

Table 52: Municipal Engagement Summary

Meeting Date	Municipality
December 10, 2013	Pickle Lake
December 10, 2013	Greenstone
December 12, 2013	Red Lake
December 12, 2013	Sioux Lookout
December 13, 2013	Marathon
February 12, 2014	Dryden
February 13, 2014	Ignace

Following the municipal engagement meetings, several themes emerged as common feedback from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

Various municipal representatives provided input that any new transmission being contemplated in northwestern Ontario should be built to 230 kV standards in order to accommodate potentially high growth and encourage economic development. In general, the OPA agrees with this philosophy if there is sufficient justification to spend the incremental cost associated with a more expensive 230 kV option compared to a less expensive 115 kV option.

The OPA considered this feedback in updating the Draft North of Dryden IRRP that was released on August 16th, 2013. In the draft IRRP, the OPA indicated that it had no preference to the voltage for the recommended new line to Pickle Lake. In this version of the IRRP, the OPA was able to find sufficient justification for initially building and operating the recommended new line to Pickle Lake to 230 kV. The justification is based on the fact that the reference scenario forecast exceeds the capability of a 115 kV line in the longer term, and the provision of option flexibility for supplying the Ring of Fire as described in Section 7.2.

Cost responsibility was another common point of feedback. Generally the municipal representatives communicated that the infrastructure being contemplated in the North of Dryden IRRP is to enable economic development. Economic development was said to provide broader benefits than the local customers and costs should therefore be shared more broadly. Cost responsibility for new transmission and distribution infrastructure will be determined by the OEB during the appropriate regulatory process. For example for applicable transmission lines, cost responsibility would be determined during the leave to construct application.

Another common theme communicated by municipal representatives was the sense of urgency to develop the near term recommendations of a new line to Pickle Lake and the line upgrades from Dryden to Red Lake. The OPA agrees that the recommendation of building a new 230 kV single circuit line to Pickle Lake and upgrading the lines between Dryden and Red Lake are required as soon as possible, and will continue to support their development within the capacity of the OPA.

8.3 Other Engagement Activities

Prior to the publication of the Draft North of Dryden IRRP, the OPA engaged with remote communities, municipalities, stakeholder groups and industry to better understand the needs of the North of Dryden sub-region and communicate options that the OPA was considering for the North of Dryden IRRP. Presentations were made to the following groups and events:

- Ontario Mining Conference – June, 2013
- Common Voice Northwest – May, 2013
- Kenora District Municipal Association AGM – February, 2013
- Central Corridor Energy Group/Wataynikaneyap Power – various meetings 2011-2014
- Sagatay Transmission L.P. – various meetings 2012-2014

- Sioux Lookout Aboriginal Advisory Management Board - Trades Conference Fall 2012
- Aboriginal Energy Forum – December 2012
- Keewaytinook Okimakanak Chiefs Annual Meeting – December 2012
- Red Lake Mining Forum – October 2012
- NWOFNTPC - various meetings 2011-2012

With the release of draft IRRP in August 2013, the OPA hosted a webinar on November 21, 2013 to provide a high-level overview of the plan and to start the dialogue on further developing and refining the plan. An archive of the webinar was posted to the OPA website for stakeholders and communities who were not able to participate.

The OPA also established a dedicated email address – northofdryden@powerauthority.on.ca – to receive written feedback on the draft IRRP and for correspondence about the plan.

9 SUMMARY OF RECOMMENDATIONS

The existing North of Dryden sub-region has met its load meeting capability. In order to accommodate the economic connection of remote First Nation communities and to enable forecasted growth in the mining sector, it is prudent to develop and implement the following recommended solutions as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long term forecast scenarios.

The estimated combined cost of recommendations (1) and (2) during the planning period is about $124 million (net present value). Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

Based on the reference scenario forecast, the recommended solutions are expected to satisfy the forecasted demand requirements for the Pickle Lake and Red Lake subsystem until beyond the end of the planning period. The high scenario forecast indicates that additional investments for the Red Lake subsystem may be required by

2030. The transmission and generation options available have relatively short lead times compared to the 2030 need date, based on the high scenario forecast. As a result, no further action needs to be taken at this time.

The OPA has also shown that under all forecast scenarios assessed in this version of the North of Dryden IRRP, transmission supply options to supply the Ring of Fire subsystem are more economic than remote generation options. The OPA therefore recommends that common infrastructure corridor planning to the Ring of Fire should include the consideration of the potential need for a transmission line to ensure economic and regulatory efficiencies. The OPA will monitor developments in the Ring of Fire subsystem to ensure potential customers, stakeholders and Aboriginal groups are aware of these findings.

The OPA will continue to monitor developments in the North of Dryden sub-region, such as: progress on the recommendations in this version of the plan, demand growth, conservation activities, and progress on developments at the Ring of Fire.

As developments in the North of Dryden sub-region reach new milestones, a new planning cycle for the sub-region will be initiated. The next planning cycle will take place within the next 1-5 years, consistent with the TSC, DSC, and the OPA's license, depending on if and when currently uncertain developments take place.

When the long-term needs for the Red Lake and Ring of Fire subsystems become more certain, reinforcement projects can be triggered in the next planning cycle with appropriate lead times to ensure that the needs will be met.

Some projects may require funding by customers, in accordance with the TSC. In these cases the projects cannot proceed until customers have committed the required resources and funding for development work to be completed. Therefore, the timing of these facilities may be dependent on when customers can identify their needs and provide commitment to the project.

Additionally, conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the North of Dryden sub-region. The OPA has and will continue to actively work with existing and future customers in the North of Dryden sub-region to pursue conservation and DG. The OPA will continue to work with interested customers to understand the availability of potential resources including conservation and customer based DG in the North of Dryden sub-region.

The recommended solutions in the North of Dryden sub-region are consistent with the broader planning and development work that is underway to ensure an adequate supply is available in the Northwest as a whole.

10 APPENDICES

10.1 List of Remote First Nation Communities in the Remote Community Connection Plan

Pickle Lake Subsystem Communities

- Sachigo Lake
- Bearskin Lake
- Kingfisher Lake
- Wawakepewin
- Kasabonika Lake
- Wunnumin Lake
- Wapekeka
- Kitchenuhmaykoosib Inninuwug (Big Trout Lake)
- North Caribou Lake (Weagamow)
- Muskrat Dam

Red Lake Subsystem Communities

- Deer Lake
- North Spirit Lake
- Poplar Hill
- Pikangikum
- Keewaywin
- Sandy Lake

Ring of Fire Subsystem Communities

- Eabametoong (Fort Hope)
- Neskantaga (Landsdowne House)
- Webequie
- Nibinamik (Summer Beaver)
- Marten Falls

Communities that are not Economic to Connect at this Time

- Peawanuk
- Fort Severn
- Gull Bay
- Whitesand

10.2 List of Terms and Acronyms

ACF	Average Capacity Factor
Board or OEB	Ontario Energy Board
C&S	Codes and Standards
CNG	Compressed Natural Gas
CTS	Customer Transformer Station
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
DSC	Distribution System Code
EA	Environmental Assessment
EE	Energy Efficiency
EM&V	Evaluation, Measurement & Verification
EUF	End Use Forecast
FIT	Feed-In Tariff Program
FN	First Nation
GAM	Global Adjustment Mechanism
GS	Generating Station
Hydro One or HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan
IRRP	Integrated Regional Resource Plan
Km	Kilometers
kV	kilovolts
kW	Kilowatts
LDC	Local Distribution Company
LMC	Load Meeting Capability
LNG	Liquefied Natural Gas
LTEP	Long-Term Energy Plan of the Ministry of Energy dated November 23, 2010
M	Million
M/MW	Million/Megawatt
Medium to Long term	(2019-2033)
MOE	Ministry of Energy
MTS	Municipal Transformer Station
MW	Megawatts
MWh	Megawatt hour

Near term	(2014-2018)
NoD	North of Dryden
NWOFNTPC	Northwestern Ontario First Nation Transmission Planning Committee
O&M	Operating & Maintenance
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria (IESO document)
PPWG	Ontario Energy Board - Planning Process Working Group's Report to the Board as part of the Renewed Regulatory Framework for Electricity
PV	Present Value
RFEI	Request for Expression of Interest
RoF	Ring of Fire
SCGT	Single Cycle Gas Turbine
SIA	System Impact Assessment
SMD	Supply Mix Directive dated February 17, 2011
SPS	Special Protection Schemes
TCPL or TransCanada	TransCanada PipeLines Limited
TOR	Terms of Reference
TS	Transformer Station
TSC	Transmission System Code

10.3 Study Methodologies

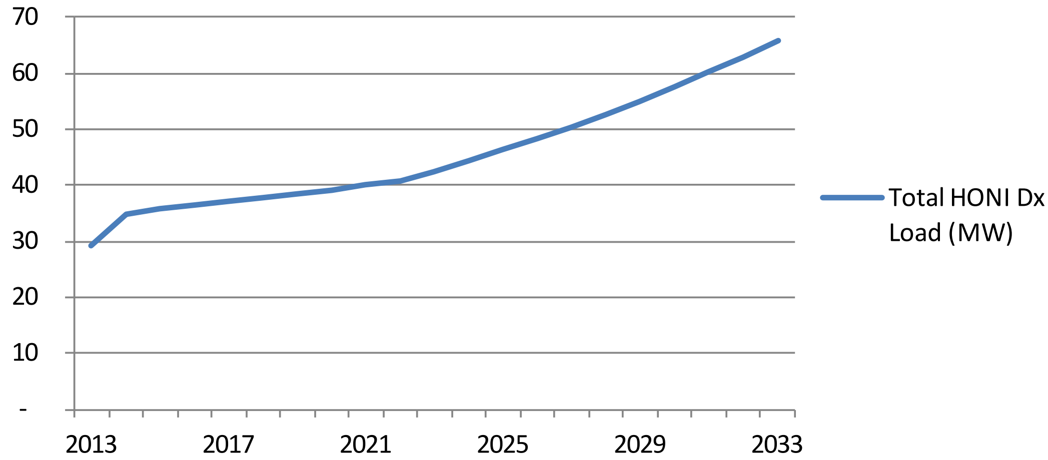
10.3.1 Hydro One Distribution - Reference Demand Forecast Methodology

Hydro One Distribution services the North of Dryden sub-region via six step-down stations:

- 115/12.5 kV Perrault Falls DS supplied by circuit E4D
- 115/44 kV Ear Falls TS supplied by 115 kV circuit E4D
- 115/44 kV Red Lake TS supplied by 115 kV circuit E2R
- 115/24.9 kV Cat Lake CTS supplied by 115 kV circuit E1C
- 115/24.9 kV Slate Falls DS supplied by 115 kV circuit E1C
- 115/27.6 kV Crow River DS supplied by 115 kV circuit E1C

The Hydro One reference demand forecast was developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. Thus historical relationships between actual load growth and economic/demographic factors were utilized in preparing the forecast. In addition, local knowledge, as well as information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast. The forecast is net of the load impact of conservation so that it is consistent with actual load for the base-year and expected load in the future in a manner consistent with the on-going provincial conservation efforts. It also reflects the expected weather impact on peak load under average peak-time weather conditions, known as weather-normal. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast.

Figure 15: North of Dryden sub-region Reference Distribution Demand Forecast (Net of Conservation)



10.3.2 **Methodology for Dependable Renewable Generation Assumptions**

Determining Dependable Wind and Solar Generation

For planning purposes, the dependable capacity of generation is the prorated amount of installed generation capacity that can be relied on to meet demand during peak need hours. Since each type of distributed generation exhibits unique behavior, specific capacity contribution assumptions were used for wind and solar to determine the dependable capacity of these resource types in the North of Dryden sub-region.

Table 53: Capacity Contributions from Wind and Solar

Resource Type	Capacity Contribution	Data Source
Wind	30%	Wind Profiles from AWS Truepower
Solar	5%	Solar Profiles from AWS Truepower

The capacity contribution of solar generation depends on both random and predictable elements, such as weather conditions, latitude, and sunrise/sunset times. The capacity contribution of wind generation depends on weather conditions and can vary significantly. To achieve an accurate representation of these resources, hourly solar and wind profiles for the Northwest zone were estimated by AWS Truepower for the years between 2004 and 2008.

The fall period is typically the most constrained supply period for the North of Dryden sub-region as it is when hydroelectric generation in the Ear Falls area is at its lowest. To calculate the expected solar and wind output in the area, hourly capacity factors from the AWS data corresponding to the top 10% of historical demand hours during October and November were averaged. This result provides a dependable level of output that can be reasonably expected from solar and wind resources in the North of Dryden sub-region during the period of peak need.

Determining Dependable Hydroelectric Generation

The hydroelectric generators located in the North of Dryden sub-region are listed below in Table 54. Lac Seul GS is an expansion of the Ear Falls GS that was undertaken by OPG with the Lac Seul First Nation.

Table 54: Existing and Contracted Hydroelectric Generation

Name	Owner	No. Unit (Total)	Unit Size (MW)	Circuit
Manitou Falls GS	Ontario Power Generation	5	4x14.9 + 1x13.5	M3E
Ear Falls GS	Ontario Power Generation	4	2x5.4 + 2x3.1	Ear Falls TS bus
Lac Seul GS	Ontario Power Generation	1	12.1	Ear Falls TS bus
Trout Lake River GS	Horizon Hydro Inc.	1	3.75	E1C

Northern hydroelectric generation is an energy limited resource known to have significantly reduced output and availability during drought conditions of the river system supplying these generating units. Neither Manitou Falls nor Ear Falls/Lac Seul are currently configured to condense. The OPA has met with OPG and are aware that configuring some select units for condense mode under drought conditions may be a low cost option to provide voltage support.

Dependable generation is defined in ORTAC as the level of generation that is available for at least 98% of hours during the evaluation period. At Manitou Falls GS, output has been at least 14.4 MW 98% of the time, while at Ear Falls GS output has been at least 6.7 MW, 98% of the time.

At Manitou Falls GS, four of the five units are connected on the secondary of one step up transformer (T1), with the fifth unit having its own transformer (T2). Because of this configuration, if T1 is unavailable, only one Manitou Falls GS unit (G5) can remain operational during the duration of the outage of T1.

The units at Manitou Falls GS units are also much larger (13.5 MW and 14.9 MW) than the Ear Falls GS units (3.1 MW and 5.4 MW), therefore the presence of one additional Ear Falls GS unit (assuming sufficient water is available during the outage of Manitou Falls T1) does not significantly improve the transfer limits in the subsystem. The single Lac Seul unit is of a similar size to the Manitou Falls GS units and its operation does significantly improve the transfer capability of the Red Lake subsystem, when it is available.

However, the performance of the Lac Seul unit and the future Trout Lake River GS during drought conditions is not yet known. Until drought condition performance is determined at these units they are assumed to be unavailable during drought conditions. The dependable generation assumptions for hydroelectric units in the Ear Falls area that have been used in this plan are summarized in Table 55.

Table 55: Existing and Contracted Hydroelectric Generation

Name	No. Units (Total)	Unit Size (MW)	Dependable Output (MW)
Manitou Falls GS	5	4x14.9 + 1x13.5	14.4
Ear Falls GS	4	2x5.4 + 2x3.1	6.7
Lac Seul GS	1	12.1	0
Trout Lake River GS	1	3.75	0

High Level Cost Assessment of Renewable Generation

The seasonal and annual variations of run of river hydroelectric generation and the intermittent output of potential wind and solar resources in the North of Dryden sub-region lead to dependable capacities for these resources that are between 5% and 30% of their nameplate capacity, as described above. If these types of resources were used to meet capacity needs for the North of Dryden sub-region, then their dependable capacity would be used to assess their contribution to meeting peak demand. To be an alternative to other generation resources or transmission reinforcements, the nameplate capacity of these renewable resources would have to be built to a level substantially greater than the capacity required for the subsystem. Furthermore, because of this over-sizing, during times of high renewable output, these resources may be partially constrained by limited existing transmission capability connecting them to the rest of the Ontario system.

Developing these resources to serve capacity needs would require between 3 MW and 20 MW of nameplate capacity to dependably supply 1 MW of load.

It is estimated that the capital cost of dependable run of river hydroelectric capacity ranges from $15 million to $65 million per MW, while wind and solar range from $15 million to $100 million per MW. The curtailment of generation would have an associated cost, or alternatively, new implementation of transmission to deliver excess energy would also have societal costs and is an alternative to renewable generation for meeting the needs of the North of Dryden sub-region. Neither of these additional costs were considered in this high level cost analysis. A summary of the results of this cost analysis is in Table 56, below.

Table 56: Summary of Renewable Generation Options

Resource Type	Firm Capacity	Capital Cost per MW of Firm Capacity	Levelized Unit Energy Cost[76]	Development Duration
Hydroelectric (Run of River)	15-30%	$16 M - $66 M /MW	$60-$110/MWh	5 to 10 Years
Intermittent Renewables	5-28%	$7.5 M - $100M /MW	$80-$400/MWh	3 Years

10.4 Technical Studies and Analysis Methodologies

The following section outlines the assumptions and methodology used for performing the technical analysis for determining the load meeting capability of the existing system, and the options being considered. The load meeting capability for options being considered are mostly limited by acceptable voltage performances. Consequently, a significant portion of the costs for options being considered is for the installation of voltage control devices. When developing cost estimates, planning level unit costs were used, which typically have an accuracy of +/-50%.

10.4.1 Base Case Setup and Assumptions

The system studies for this plan were conducted using PSS/E Power System Simulation software. The reference PSS/E case was adapted from the base case that was produced by the IESO for the 2012 North of Dryden Feasibility Study.

Bulk System Assumptions

The North of Dryden sub-region is connected to the bulk transmission system at Dryden TS. The forecasted capacity requirements for the North of Dryden sub-region are coordinated with the West of Thunder Bay IRRP. Therefore, for the purpose of this assessment, it is assumed that the bulk system supply to the North of Dryden sub-

[76] Levelized Unit Energy Cost (LUEC) is a method to compare electricity system resources on a $/MWh basis, considering the costs incurred (capital, fixed, variable, fuel, etc.) and the production of energy over the lifetime of the resource, discounted appropriately. LUEC assumes that all energy generated can be delivered without transmission constraints.
.

region will be stable. A healthy supply voltage from the bulk 230 kV (nominal) system of 245 kV has been assumed.

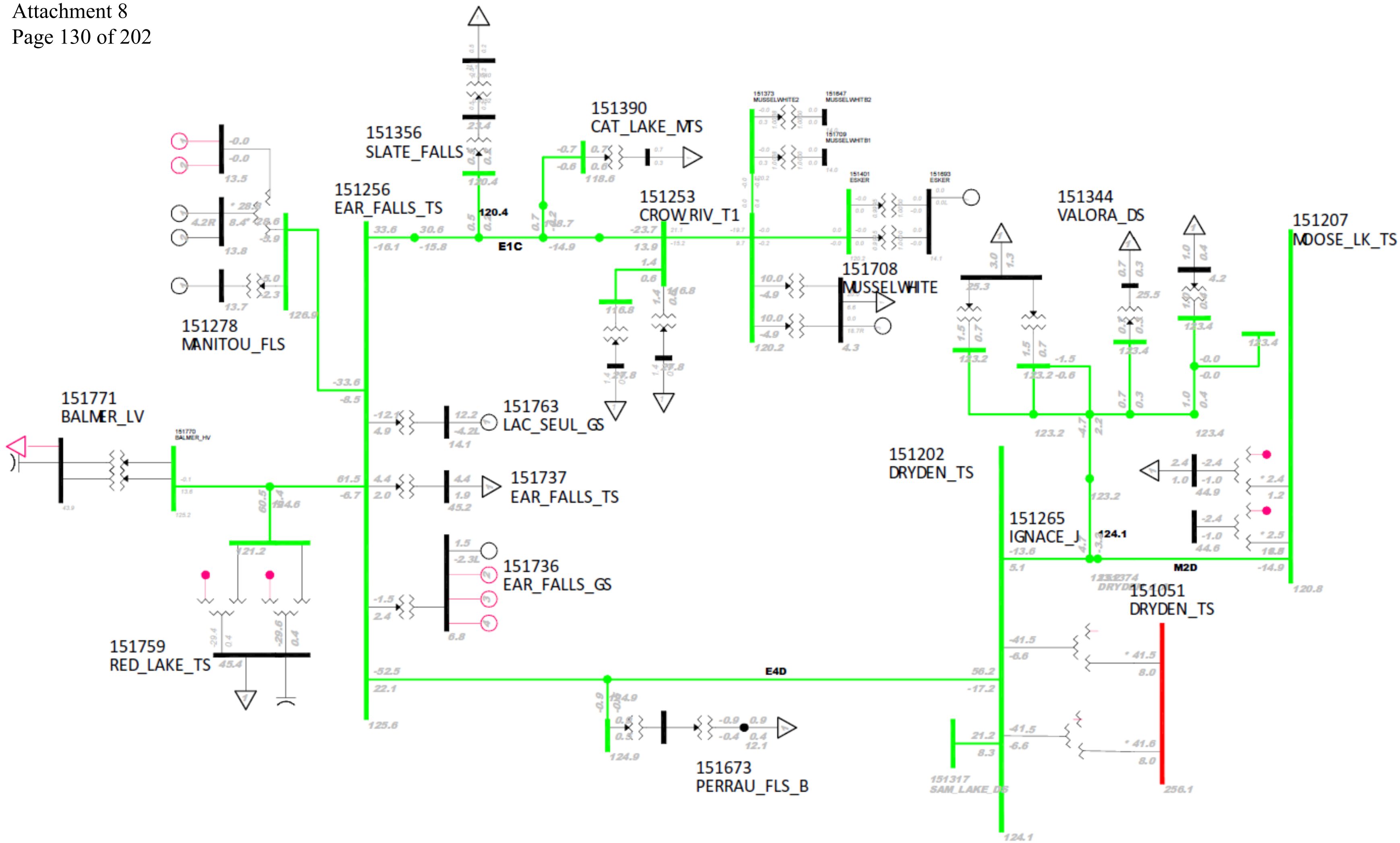
Local Area Assumptions

These load flow cases include the following assumptions:

- Dependable (drought) level hydroelectric generation, which totals 21.1 MW in the Ear Falls area (Manitou Falls GS (14.4 MW), Ear Falls GS (6.7 MW))
- Summer ambient temperature of 30°C and 0-4 km/hr wind for ampacity of overhead transmission circuits
- Peak forecasted load corresponding to the reference, high, and low scenarios for the near term and medium to long term
- All proposed 115 kV circuits had line characteristics equivalent to that of a 477 kcmil ACSR conductor (similar to existing M2D), and all proposed 230 kV circuits had line characteristics equivalent to that of a 795 kcmil ACSR conductor (similar to existing circuit D26A)
- The 115 kV step-down transformers at Mc Faulds (Ring of Fire mines) were assumed to be similar to the existing transformers at Red Lake TS. Other 115 kV step-down transformers were assumed to be similar to the existing transformers at Crow River DS for loads greater than 3 MVA, or the Slate Falls transformer for loads smaller than 3 MVA. The Pickle Lake 230/115 kV autotransformer was assumed to be similar to the existing Lakehead autotransformers.
- Dependable capacity at Trout Lake River GS is assumed to be 0 MW
- 5% of installed solar capacity is assumed to be dependable. This includes four microFIT projects in Red Lake providing capacity of 39.3 kW and one microFIT project in Ear Falls with an capacity of 10 kW, providing a 2.5 kW of dependable output
- For steady state and voltage assessment, the loads are modeled as constant megavolt-ampere (MVA)
- All new voltage control devices are assumed to be Static Var Compensation (SVC) devices

- It was assumed that the loss of voltage control devices connected at load stations (McFaulds, Esker, Musselwhite, Red Lake, Balmer, Sandy Lake, Pickle Lake area Mine) would also result in the loss of the associated load.

Figure 16: North of Dryden 2012 Peak Load Flow Case



10.4.2 **Application of IESO Planning Criteria**

In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)[77]. In accordance with ORTAC, the transmission system supplying a local area shall have sufficient capability under peak demand conditions to withstand specific outages prescribed by ORTAC while keeping voltages, line and equipment loading within applicable limits. In determining the load meeting capability for each subsystem, ORTAC requires certain conditions to be respected. The supply options that are discussed for the North of Dryden sub-region assume that where new lines are built parallel to existing lines, some or all of the incremental load that is enabled for connection to the system, may be curtailed in the event of a forced outage of either line. This following is an excerpt from Section 7.1 of ORTAC which states:

> "The *transmission system* must be planned to satisfy *demand* levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The *transmission system* must exhibit acceptable performance, as described below, following the design criteria contingencies defined in sections 2.7.1 and 2.7.2. For the purposes of this section, an element is comprised of a single zone of protection.
>
> With all transmission *facilities* in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.
>
> With any one element out of service3, equipment loading must be within applicable long-term *emergency* ratings, voltages must be within applicable *emergency* ranges, and transfers must be within applicable normal condition stability limits. Planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150MW load interruption limit reflects past planning practices in Ontario."

Additionally, the following were assumed in this study to comply with ORTAC:

- Run of river hydroelectric generation should be assumed at a level that is available 98% of the time (ORTAC Section 2.6);

[77] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

- Load power factors is assumed to be 0.95 at the low voltage busbar to comply with the Market Rule of 0.9 at the defined meter point at the HV busbar (ORTAC Section 2.4);
- Voltage operating range of 113 kV to 132 kV for the 115 kV nominal system, and 220 kV to 250 kV for the 230 kV nominal system (ORTAC Section 2.4);
- Pre-contingency voltage maintained to the greater of (ORTAC Section 4.2):
    - At least 10% margin above the instability point
    - Minimum continuous voltage pre-contingency: 113 kV for 115 kV nominal system, and 220 kV for 230 kV nominal system
    - That which results in a post-contingency voltage of at least 108 kV for 115 kV nominal system, and 207 kV for 230 kV nominal system
- All line and equipment loading is within the continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service (ORTAC Section 4.7.2 and 7.1); and
- If the subsystem has transmission connected generation, the largest generator unit is assumed to be on outage pre-contingency and not available post-contingency.

The load meeting capability for each subsystem and each option are determined with the aid of PSS/E simulation, which represents a full model of the system, accounting for active and reactive power flows, losses, voltage drops, etc.

Table 57: Conditions for Determining Subsystem LMC

Local Area Supply	Conditions for LMC
Single Radial Line	Limit of the line during normal operating conditions.
Single Radial Line + Local Generation	Limit of the line during normal conditions; and Loss of the largest generating unit.

10.4.3 Technical Study Procedures

Once the needs for the subsystems were determined based on an assessment of the existing system and forecast net demand growth, the technical study identified how various options could meet the identified needs. From these needs, a range of generation and transmission options were developed that are capable of partially or fully meeting the identified needs. The capability of the options to serve the needs including the amount of voltage control required to meet the required LMC was determined.

Contingencies Considered in Option Assessment

A detailed list of the contingencies considered for the North of Dryden sub-region is outlined below in Table 58. All contingencies are limited to the loss of a single element (N-1) considering pre-contingency outage conditions consistent with ORTAC.

Table 58: Contingencies Considered in the Technical Study

Subsystem	Supply Option	Contingencies
Pickle Lake	CNG generation at Pickle Lake	Loss of single generating unit (10 MW) at Pickle Lake
		Loss of Manitou Falls GS
	New Line to Pickle Lake	N/A
Red Lake	NG generation at Red Lake	Loss of single generating unit (10 MW) at Red Lake
		Loss of Manitou Falls GS
	New Line to Ear Falls	Loss of New Line
		Loss of Manitou Falls GS
Ring of Fire	All	N/A

Determining Voltage Control Requirements

For each option in each subsystem, base cases were developed for both peak and light load conditions. Each subsystem was considered independently, and the effects of each option on the bulk system around Dryden TS and/or at Marathon TS were included.

Location and size of the voltage control devices for each test case was determined under the following load scenarios to satisfy the assumptions listed above.

1. Peak load conditions, all elements in service: This test determined the voltage control devices are required to ensure sufficient margin from the voltage collapse point. Voltage control devices were used to maintain the voltage within the ranges stated in the assumptions.

2. Zero load conditions: This test determined the amount of voltage control required to manage high voltages.

3. Light load conditions, all elements in service: This test was used to determine the required switching size and range of the voltage control devices.

4. Peak load conditions, largest local element out of service: In areas where contingencies were tested, voltage control device requirements before tap changing were determined.

Determining Load Meeting Capability of Options

This study uses the base cases that were developed for the peak load scenario in determining voltage control requirements, as stated above. For each subsystem, the LMC of the option following the installation of all facilities and voltage control devices that are required to meet the peak load forecast was determined for each option for each forecast scenario.

The LMCs for each option were determined using the following procedure:

1. The range of voltage control that was determined in the previous analysis was assumed to be available.

2. Peak load was assumed as a base. Thermal loading of transmission equipment was assessed.

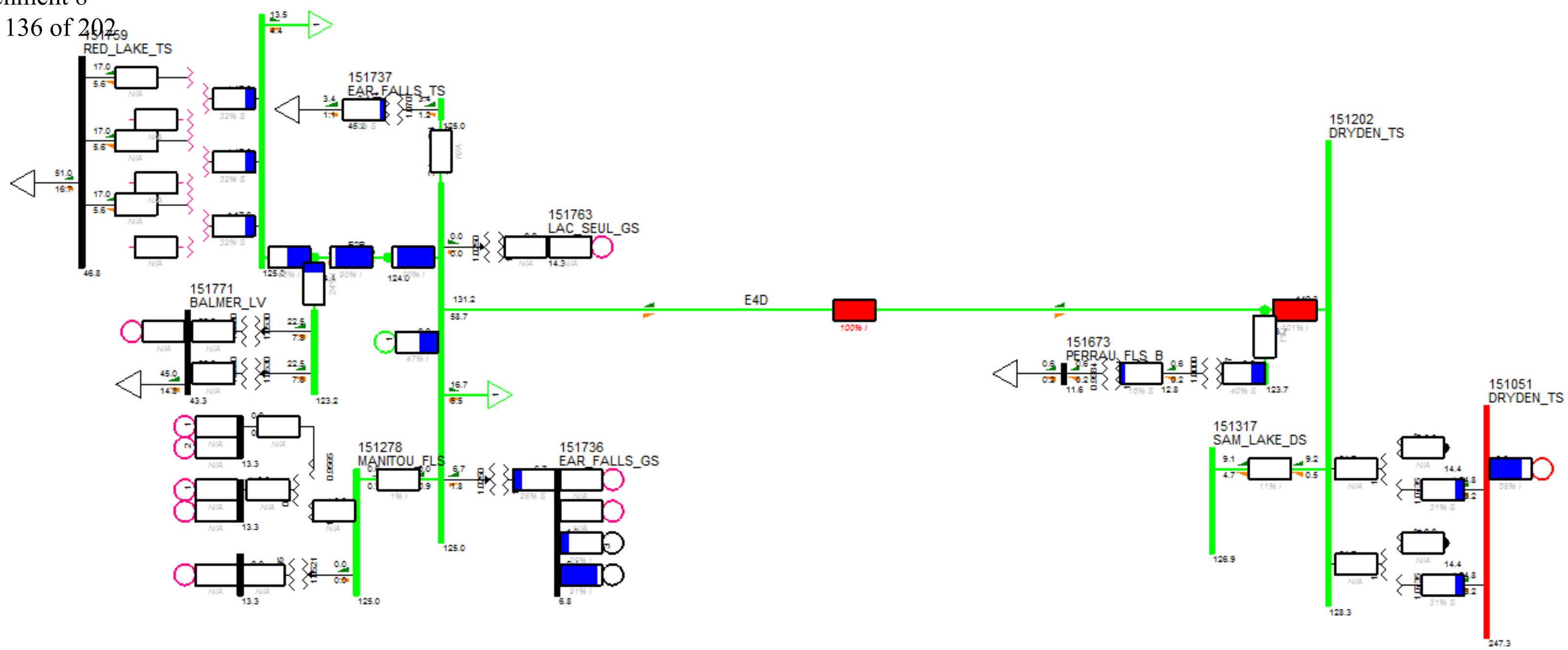
3. Where there was existing thermal capacity on transmission equipment, load was increased and new voltage control requirements were established, to determine the LMC. Load was increased at a central system bus within the subsystem (Pickle Lake area TS for the Pickle Lake subsystem, Ear Falls TS for the Red Lake subsystem, Mc Faulds TS for the Ring of Fire subsystem).

4. Following this, the system was tested allowing voltage control requirements to increase within reasonable limits.

More detailed studies for particular reinforcements may determine that voltage control devices can be located in alternative places closer to large loads, which may be found to optimize their value and reduce the overall cost. Specific connection requirements for individual customers, including requirements for additional voltage control devices will be identified by the IESO in future System Impact Assessments ("SIA").

A sample load flow case that was used to determine the LMC of the Red Lake subsystem after the upgrade of E4D and E2R is provided in Figure 17 below. In this case, the LMC for subsystem is 130 MW.

Figure 17: Sample of Methodology – Determining Post-Upgrade LMC of E4D and E2R Upgrade



10.5 Existing System Description and Load Meeting Capability

The North of Dryden electricity system is shown in Figure 18.

Figure 18: Existing North of Dryden Transmission System

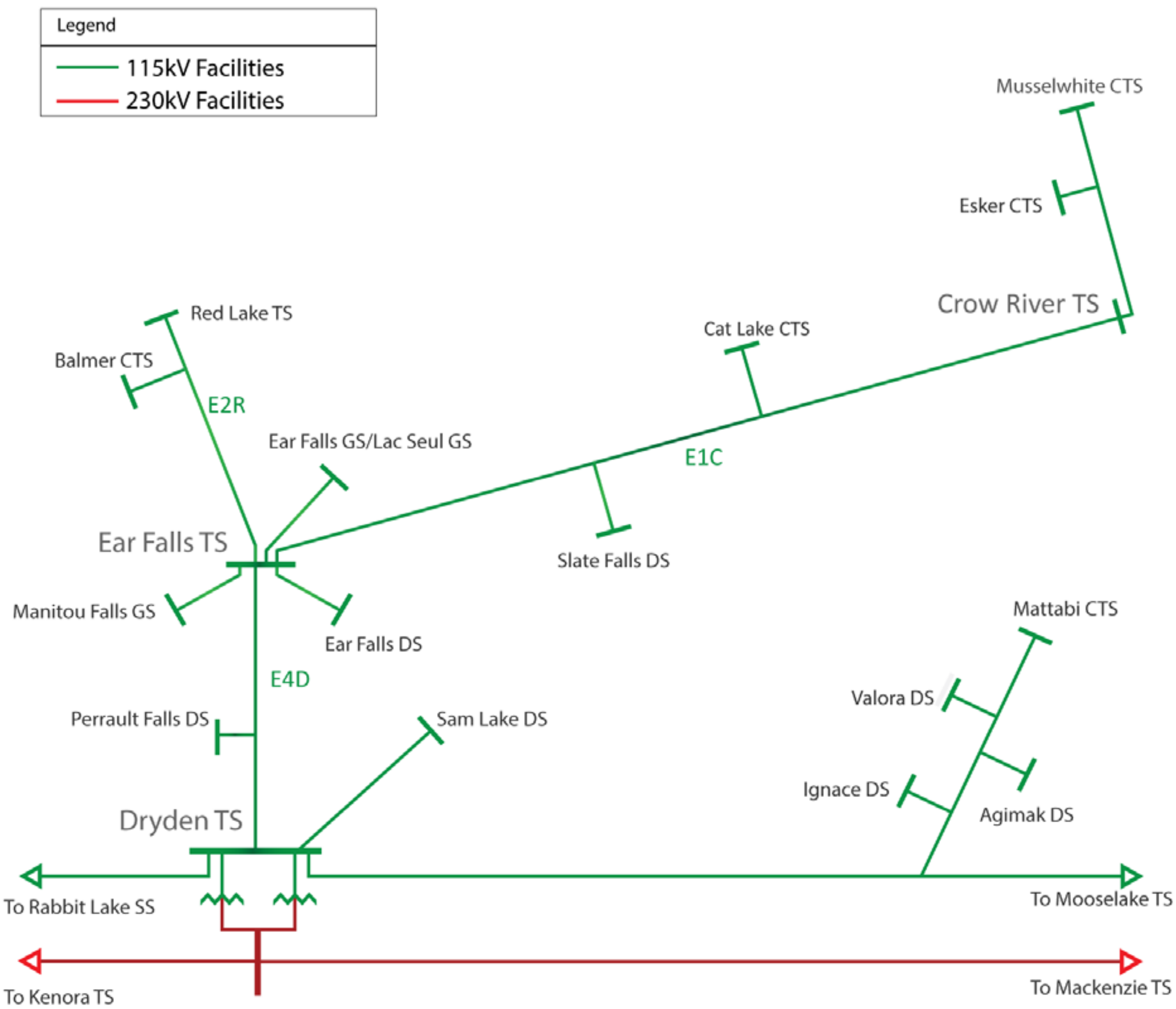
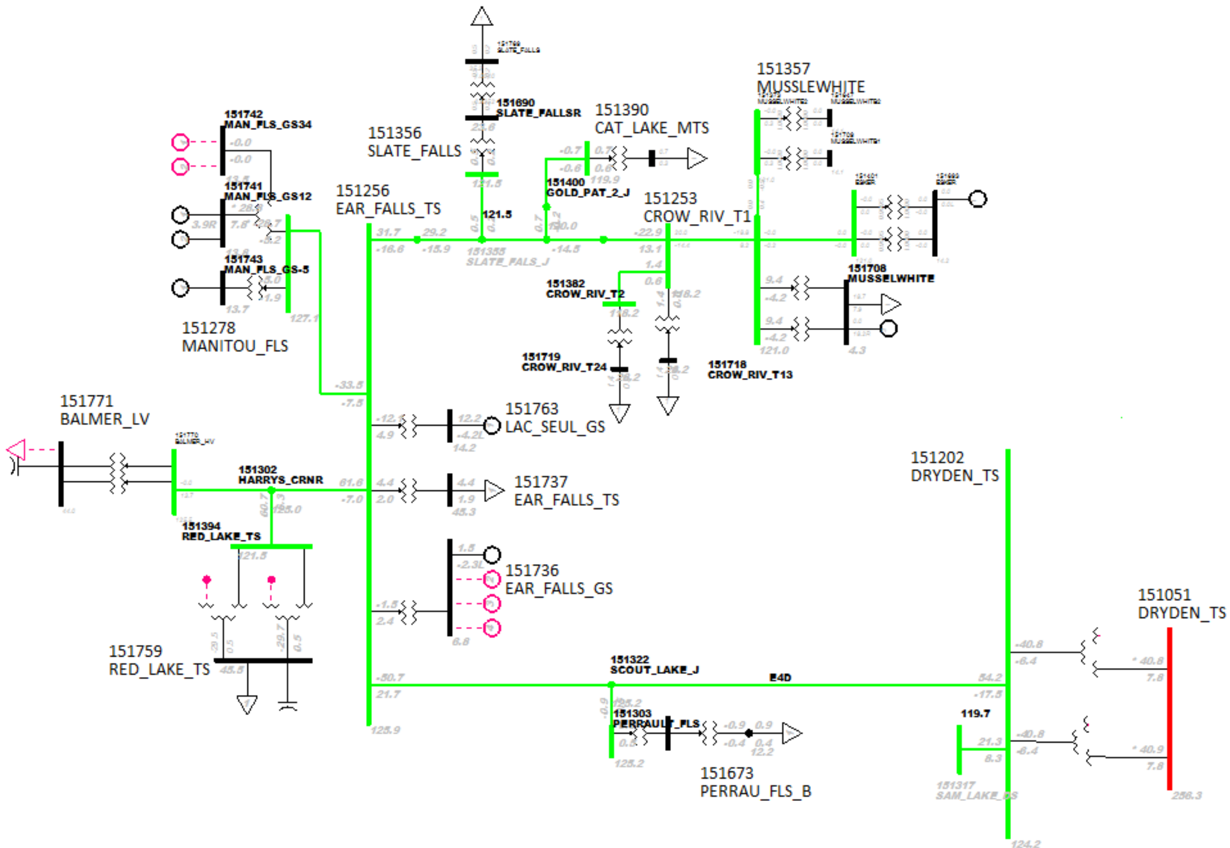


Figure 19: Existing North of Dryden Transmission System Load Flow Plot



Pickle Lake Subsystem

The Pickle Lake subsystem includes all load currently and planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as Musselwhite mine. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are planned to connect to Pickle Lake via a transmission line to Crow River DS.

Currently, the Pickle Lake subsystem has an LMC of 24 MW. Due to losses on the line E1C, supply of close to 35 MW is required from Ear Falls TS to serve this load along the line and at Pickle Lake. The LMC for the Pickle Lake subsystem is determined by the load that can be met during normal operating conditions.

Red Lake Subsystem

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities that lie north of Red Lake that are planned to connect to Red Lake TS. There is 102.2 MW of hydroelectric generation at Ear Falls/Lac Seul GS and at Manitou Falls GS.

Currently, the E4D and Ear Falls area generation is capable of supplying 85 MW from Ear Falls TS, which includes 61 MW in the Red Lake subsystem and 24 MW in the Pickle Lake subsystem.

Ring of Fire Subsystem

The Ring of Fire subsystem includes five remote communities that are planned for connection to the provincial transmission system as well as potential future industrial customers at the Ring of Fire. This subsystem may be connected to the provincial transmission system either at Pickle Lake, Marathon TS, or east of Nipigon.

The Ring of Fire subsystem is not currently supplied from the IESO-controlled grid and thus has a load meeting capability of 0 MW. However the 5 remote communities are currently served by local diesel generation in their communities.

10.6 Analysis of Recommended Options

As indicated in Section 0, the recommended options for the North of Dryden sub-region are:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

   For the list of assumptions and procedure pertaining to the assessment of generation options, refer to Section 10.7. For a list of assumptions and procedure pertaining in the assessment of transmission options, refer to Section 10.8

Recommendation 1: New single circuit 230 kV line to Pickle Lake and supporting facilities

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

Table 59: Summary of Load Meeting Capability of Recommendation

Recommendation	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
230 kV line to Pickle Lake	136 MW	160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Table 60 outlines the cash flows used for the net present value economic analysis. Figure 20 and Figure 21 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

Table 60: Summary of Cashflow for New Line to Pickle Lake at 230 kV[78]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				28.4																
O&M				1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Annual Cost	0.0	0.0	0.0	168.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Annual Amortized Cost				9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Cumulative PV	0.0	0.0	0.0	8.4	16.4	24.1	31.5	38.7	45.5	52.1	58.5	64.6	70.5	76.1	81.5	86.8	91.8	96.6	101.2	105.7

[78] Includes compensation required to supply Reference load forecast scenario (78 MW in 2033).

Figure 20: New 230 kV line to Pickle Lake Diagram

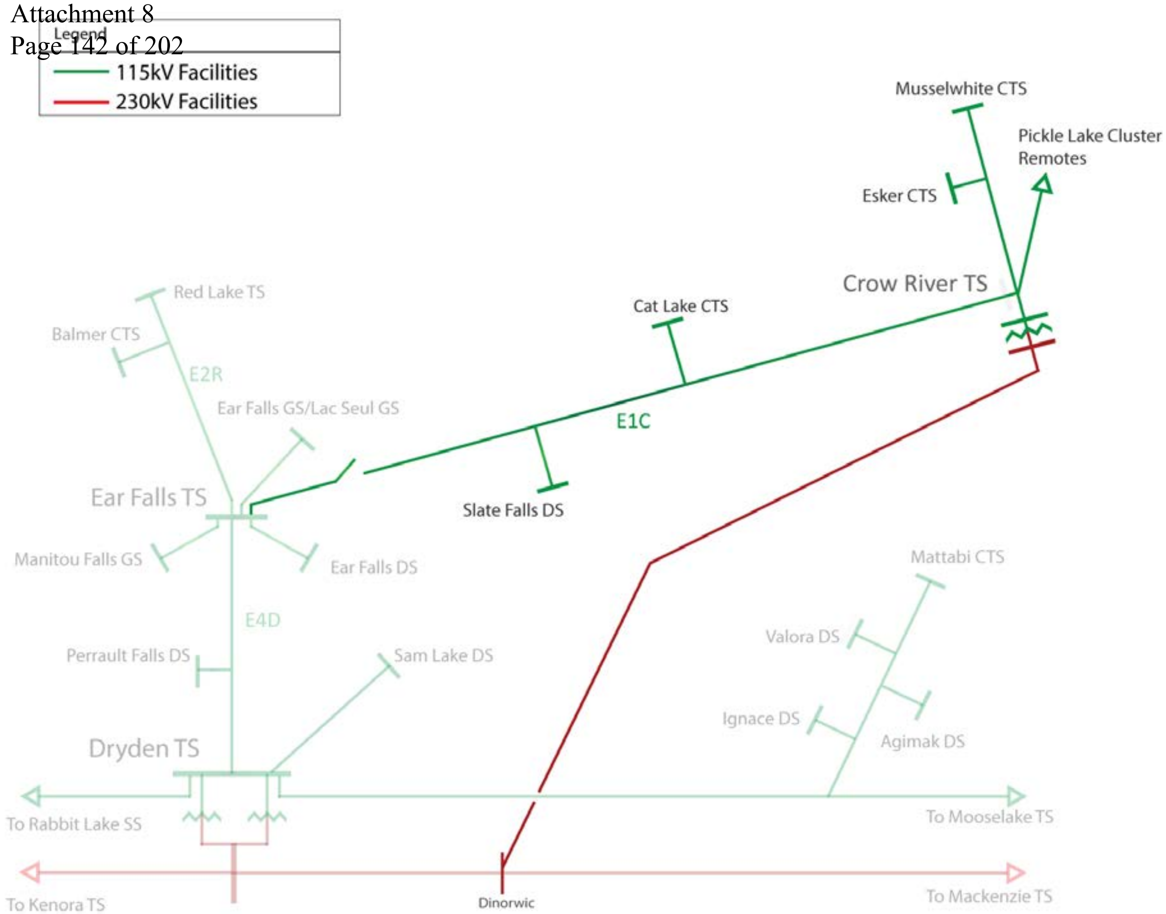
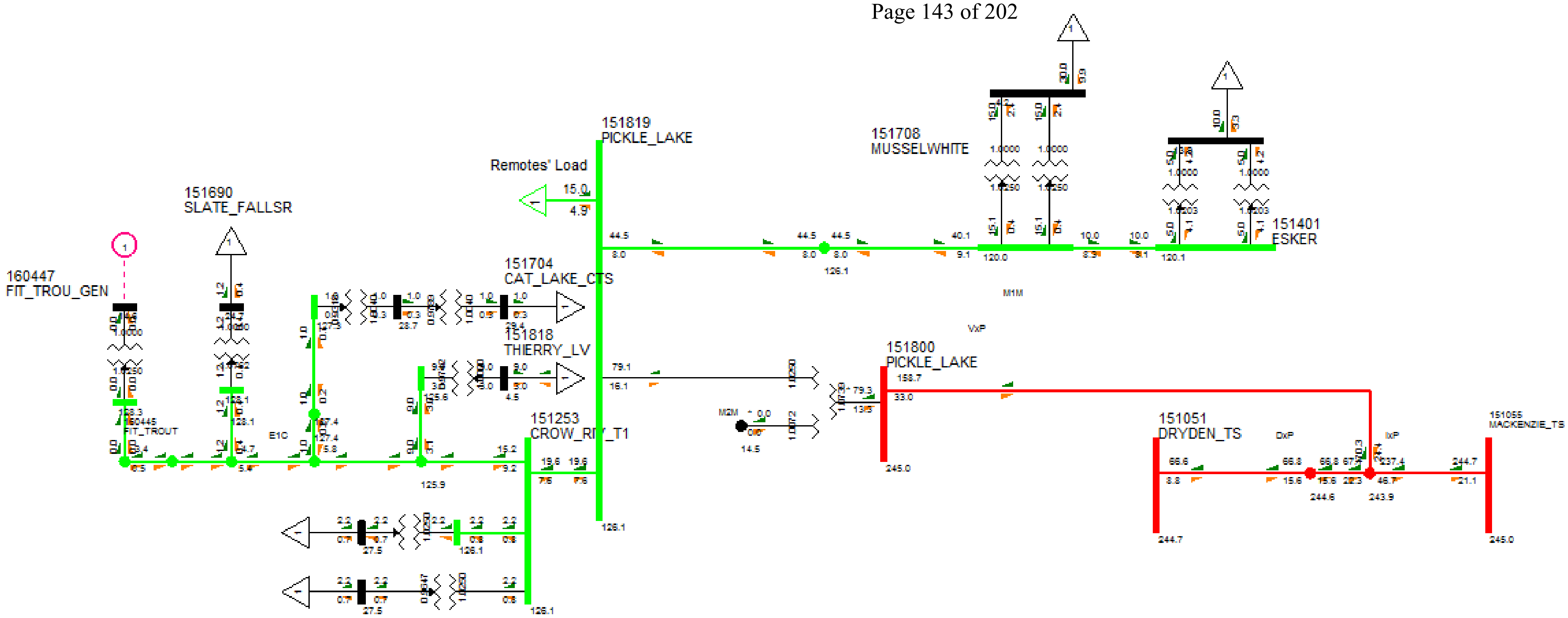


Figure 21: 230 kV Line Option Pickle Lake Subsystem Configuration



Recommendation 2: Upgrade circuits E4D and E2R and supporting facilities

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

Table 61: Summary of Load Meeting Capability of Recommendation

<table>
<tr><th>Recommendation</th><th>Incremental Capacity</th><th>Load Meeting Capability</th><th>Low Forecast Demand</th><th>Reference Forecast Demand</th><th>High Forecast Demand</th></tr>
<tr><td rowspan="2">Upgrade E4D and E2R
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>34 MW</td><td>95 MW</td><td rowspan="2">100 MW</td><td rowspan="2">109 MW</td><td rowspan="2">136 MW</td></tr>
<tr><td>35 MW</td><td>130 MW</td></tr>
</table>

Table 62 outlines the cash flows used for the net present value economic analysis. Figure 22 and Figure 23 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

Table 62: Summary of Cashflows for Upgrade to E4D and E2R

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line Cost	0.0	5.0																		
Station Cost	0.0	10.5																		
O&M	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Annual Cost	0.0	15.7	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Annual Amortized Cost	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Cumulative PV	0.0	0.8	1.6	2.4	3.2	3.9	4.6	5.2	5.9	6.5	7.1	7.7	8.2	8.7	9.2	9.7	10.2	10.6	11.1	11.5

Figure 22: E4D and E2R Upgrade Diagram

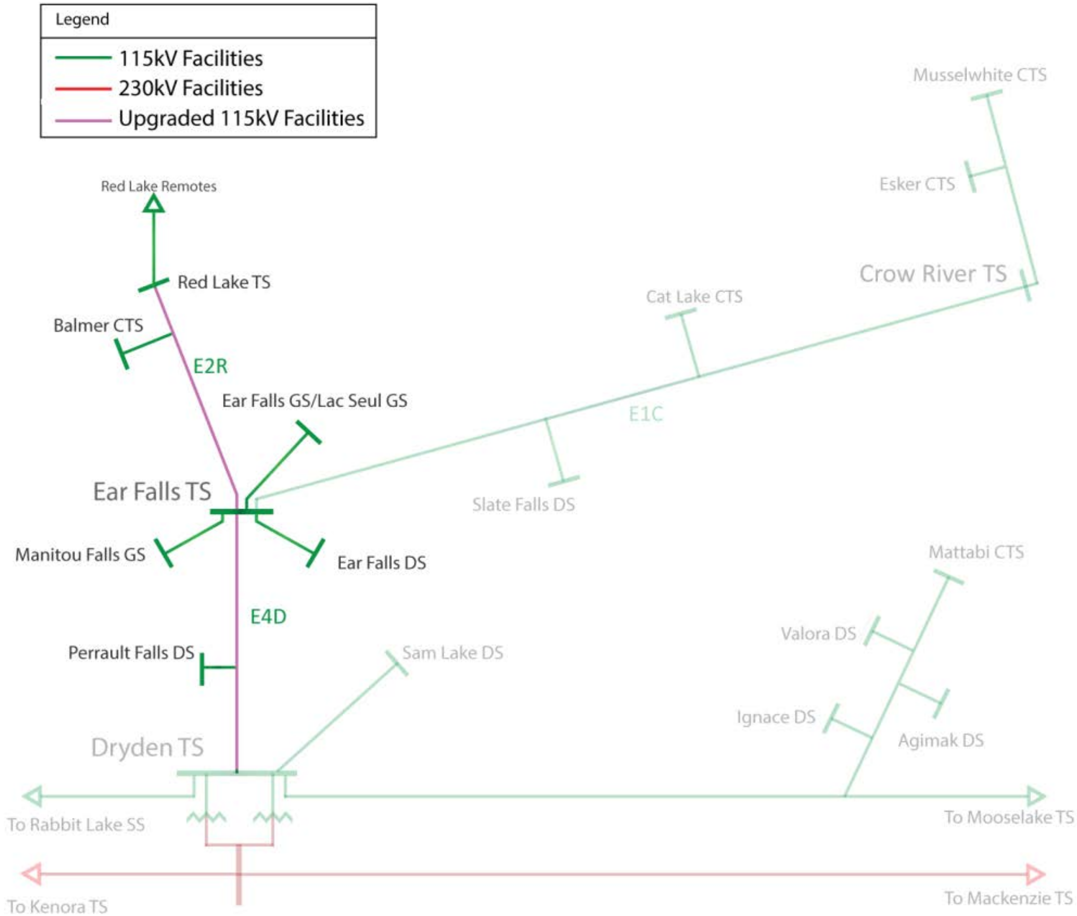
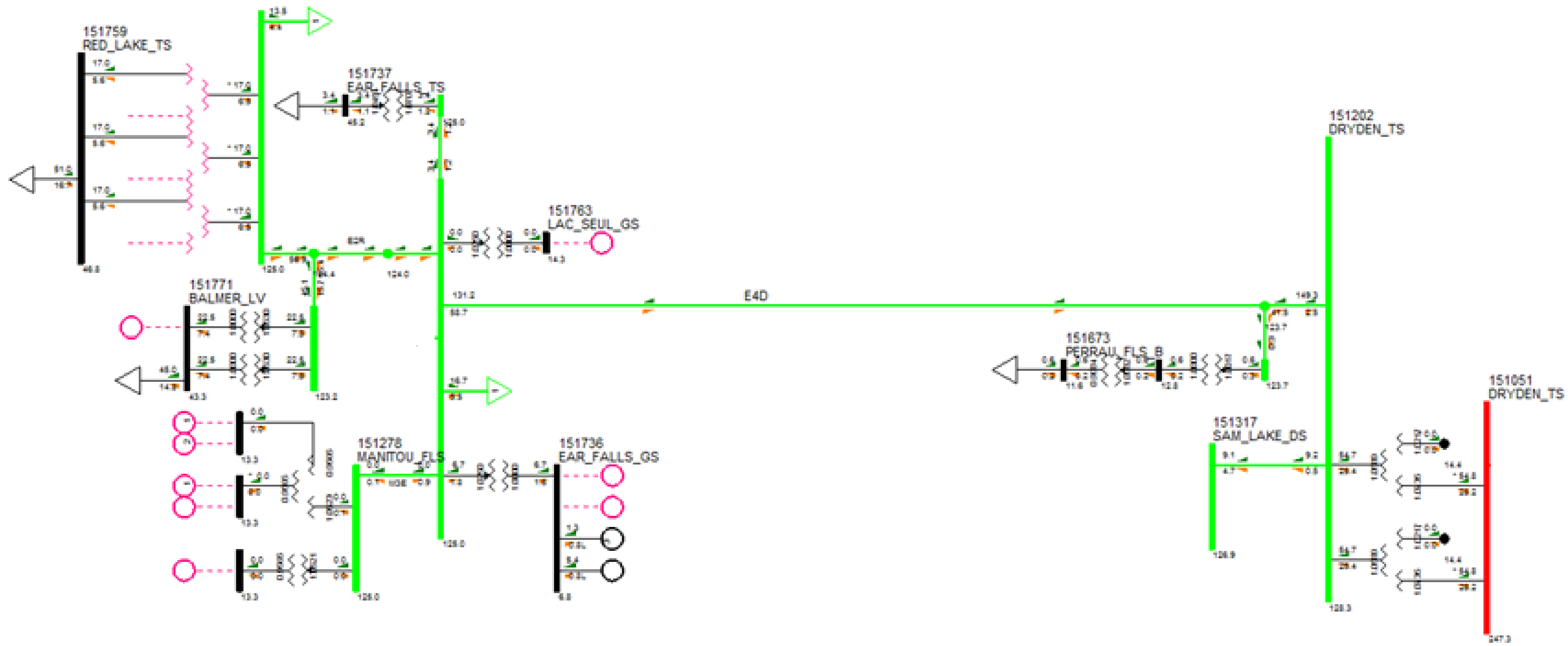


Figure 23: E4D and E2R Upgrade Red Lake Subsystem Configuration



Recommendation 3: Manitou Falls condense operation during drought conditions

In order to accommodate future growth in the Red Lake subsystem, new voltage control devices would need to be installed in the Ear Falls and Red Lake areas. New voltage control devices would be required in order to release the thermal capability provided to the Red Lake subsystem from the system upgrades being recommended.

OPG has informed the OPA that Manitou Falls units G1, G2, and G3 could be made to condense with minor maintenance work. Units G1, G2, and G3 would have a capability of approximately +/-14 MVar each, for a total of +/- 42 MVar. The OPA anticipates that the NPV cost associated with enabling and operating the condense features over the planning period is likely to be significantly less than the NPV cost of installing new voltage control devices.

10.7 Generation Options

For each of the three subsystems, at least one generation option was studied in detail. However, due to the different nature of each system, and thus the differing needs, each system was approached with a unique methodology to ensure that the generation option/s studied reflect the need of the subsystem.

The assumptions and methodologies used for developing the generation options are described below.

10.7.1 Pickle Lake Subsystem

Assumptions

The following assumptions were used to estimate the cost of CNG electricity generation in the Pickle Lake subsystem:

- Pickle Lake subsystem will remain connected to Ear Falls TS and 24 MW of load in the Pickle Lake subsystem will be served from Ear Falls TS

- Forecasted demand greater than 24 MW in the Pickle Lake subsystem (including remote communities in the Ring of Fire subsystem connecting at Pickle Lake) would be served by CNG fueled generation at Pickle Lake
- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed
- Generation would be fueled mainly by CNG, which would be compressed and transported from TCPL pipeline in the Ignace area via Highway 599
- Decanting stations would be required to decompress the natural gas for use
- CNG fuel delivery would be on a just in time basis due to challenges with large scale on-site CNG storage
- If CNG is unavailable generators will run on diesel, cost of supplying diesel and storage has not been included
- A sufficient number of trailers would be required to transport CNG as well as provide for some limited on-site storage to ensure a stable flow of fuel
- A Special Protection System triggered by the loss of more than one generator in the new facility, may be required to automatically shed load sufficient to maintain operation of E1C within appropriate limits
- Discrete generator unit sizes of 9.5 MW

Study Procedure

To determine the feasibility and estimate the cost of implementing a CNG generation facility in the Pickle Lake subsystem, the following procedure was undertaken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity at Pickle Lake that would be required to meet the peak forecast demand of the subsystem.
2. Using established transmission limits, hydroelectric generation profiles and load profiles for the subsystem, the capacity and energy that would need to be served by new CNG generation resources was estimated.
3. Using energy requirements estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;

4. Using generator capacity, number of trailers and annual energy requirements, capital, operations and maintenance, and fuel costs of the system were calculated.
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

Planning Level Assessment

A summary of the technical capability of the generation options that were considered for the Pickle Lake subsystem is summarized below.

Table 63: Summary of Capacity for Gas Generation at Pickle Lake

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
CNG Generation at Pickle Lake (38 MW)	19 MW	43 MW	41 MW	78 MW	90 MW
CNG Generation at Pickle Lake (47.5 MW)	23.5 MW	47.5 MW			
CNG Generation at Pickle Lake (76 MW)	57 MW	81 MW			
CNG Generation at Pickle Lake (85.5 MW)	66.5 MW	90.5 MW			

*Requires continued supply of 24 MW of load via E1C from Ear Falls

**Includes demand for Ring of Fire remote communities (7 MW)

The cost of supplying the growth needs of the Pickle Lake subsystem with CNG fueled generation are shown in Table 64 through Table 69. Figure 24 shows operation of the Pickle Lake subsystem with this option in the peak load case. Voltage profiles throughout the subsystem remain healthy in the general range of 118 kV to 125 kV. The installation of generation at Pickle Lake also provides some voltage control to the Pickle Lake subsystem.

Table 64: Summary of Cost for 38 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	56.8	0.0	0.0	0.0	4.7	0.0	0.0	0.0	4.0	0.0	16.0	0.0	3.0	0.0	0.0	0.0	2.9
O&M and Fuel	0.0	0.0	0.0	10.5	10.2	9.8	9.4	9.1	8.7	8.4	8.1	7.7	7.4	5.3	5.3	5.3	5.3	5.3	5.3	5.4
System Gen Credit	0.0	0.0	0.0	0.0	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Total Annual Gx Cost	0.0	0.0	0.0	67.2	8.7	8.3	7.9	12.2	7.2	6.9	6.6	10.2	6.0	19.8	3.8	6.8	3.8	3.8	3.8	6.8
Annual Amortized cost	0.0	0.0	0.0	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	10.3	20.3	29.8	39.0	47.9	56.4	64.5	72.4	80.0	87.2	94.2	100.9	107.4	113.6	119.6	125.3	130.8

Table 65: Summary of Cost for 47.5 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	66.4	0.0	0.0	0.0	7.2	0.0	0.0	0.0	8.0	0.0	27.7	0.0	5.6	0.0	0.0	0.0	6.4
O&M and Fuel	0.0	0.0	0.0	12.7	13.0	13.3	13.6	13.9	14.2	14.6	14.9	15.3	15.7	9.7	10.1	10.4	10.8	11.2	11.7	12.2
System Gen Credit	0.0	0.0	0.0	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1
Total Annual Gx Cost	0.0	0.0	0.0	79.1	5.9	6.1	6.4	14.0	7.1	7.4	7.8	16.2	8.5	30.2	2.9	8.8	3.7	4.1	4.6	11.5
Annual Amortized cost	0.0	0.0	0.0	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	12.1	23.7	34.9	45.6	56.0	65.9	75.5	84.6	93.5	102.0	110.1	118.0	125.5	132.8	139.8	146.5	152.9

Table 66: Summary of Cost for 76 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	124.2	0.0	0.0	0.0	9.6	0.0	0.0	0.0	12.8	0.0	52.4	0.0	15.2	0.0	0.0	0.0	18.4
O&M and Fuel	0.0	0.0	0.0	16.0	16.3	17.8	18.4	19.9	21.2	22.6	24.0	25.6	27.0	25.9	27.3	28.9	30.4	31.9	33.4	35.1
System Gen Credit	0.0	0.0	0.0	0.0	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1
Total Annual Gx Cost	0.0	0.0	0.0	140.2	2.2	3.7	4.3	15.3	7.1	8.5	9.9	24.2	12.9	64.1	13.2	30.0	16.3	17.8	19.3	39.4
Annual Amortized cost	0.0	0.0	0.0	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7
Cumulative PV of Amortized cost	0.0	0.0	0.0	22.8	44.8	65.9	86.1	105.7	124.4	142.4	159.8	176.5	192.5	207.9	222.7	237.0	250.7	263.9	276.5	288.7

Table 67: Summary of Cost for Compensation Associated with up to 76 MW of Gas Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost				8.1																
O&M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	8.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost				0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cumulative PV	0.0	0.0	0.0	0.4	0.8	1.2	1.5	1.9	2.2	2.5	2.8	3.1	3.4	3.7	4.0	4.2	4.5	4.7	4.9	5.1

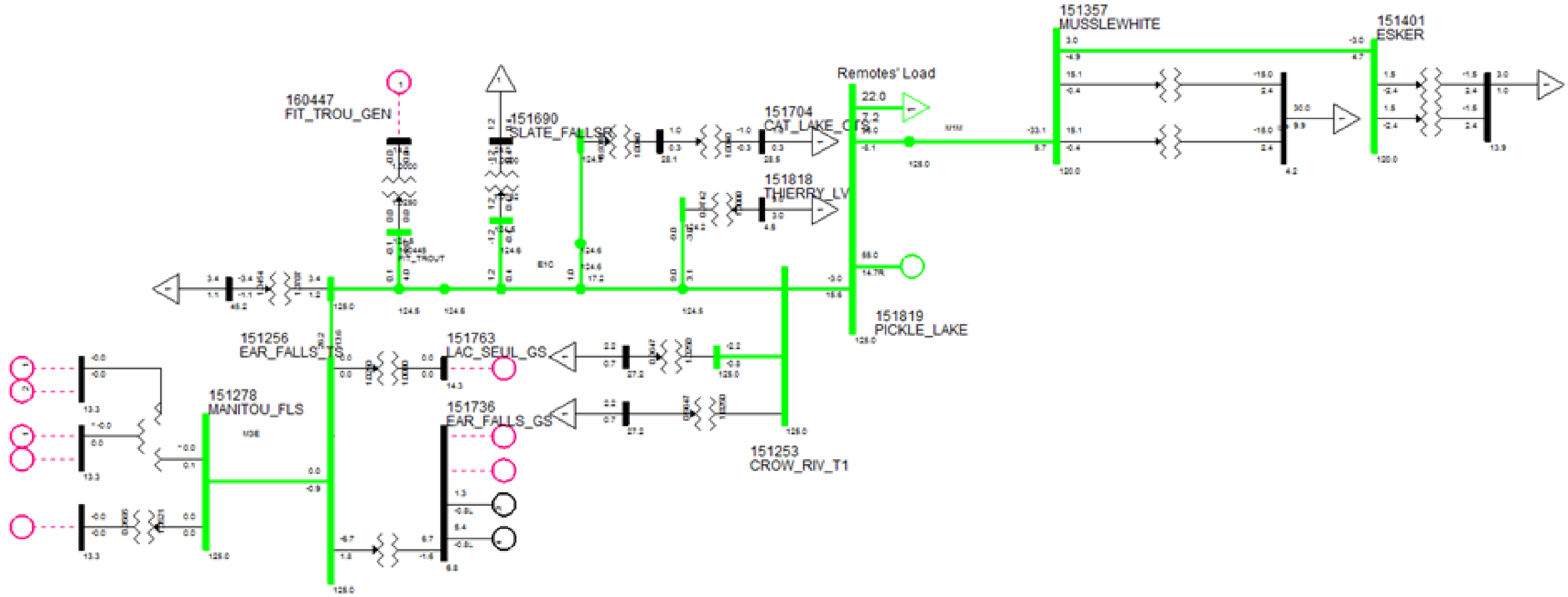
Table 68: Summary of Cost for 85.5 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	125.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	15.2	0.0	52.4	0.0	18.4	0.0	0.0	0.0	22.4
O&M and Fuel	0.0	0.0	0.0	17.1	17.3	22.0	22.5	24.1	25.4	26.8	28.2	29.8	31.2	32.6	34.1	35.7	37.2	38.7	40.2	41.9
System Gen Credit	0.0	0.0	0.0	0.0	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4
Total Annual Gx Cost	0.0	0.0	0.0	142.1	0.0	4.6	5.1	18.7	8.0	9.4	10.8	27.6	13.8	67.6	16.7	36.7	19.8	21.3	22.8	46.9
Annual Amortized cost	0.0	0.0	0.0	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3
Cumulative PV of Amortized cost	0.0	0.0	0.0	24.3	47.7	70.2	91.8	112.6	132.5	151.8	170.2	188.0	205.1	221.5	237.3	252.5	267.1	281.1	294.6	307.6

Table 69: Summary of Cost for Compensation Associated with up to 85.5 MW of Gas Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost				14.7																
O&M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	14.8	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost				0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.7	1.4	2.1	2.8	3.4	4.0	4.6	5.2	5.7	6.2	6.7	7.2	7.7	8.1	8.5	8.9	9.3

Figure 24: Generation Option Pickle Lake Subsystem Configuration



10.7.2 Red Lake Subsystem Generation Options

Assumptions

The following assumptions were used to estimate the cost of natural gas electricity generation in the Red Lake subsystem:

- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area for 30 MW generation (near-term) option;
- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area and a new gas pipeline to future customer(s) for the 60 MW (long-term) option;
- Pipelines are assumed to be available and associated costs are not included in this analysis (except gas management charges). New pipeline capacity required for the second 30 MW of gas generation at Ear Falls is assumed to be linked to a future potential load customer, therefore if the incremental gas capacity is not developed neither will the load be present in the subsystem; and
- Discrete generator unit sizes of 9.5 MW.

Study Procedure

To estimate the cost of implementing natural gas generation in the Red Lake subsystem, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity required to meet the need of the Red Lake subsystem;
2. Using established transmission limits, hydroelectric generation profiles and the identified need for the subsystem, determine the capacity and energy that new generation resources would need to served;
3. Using established unit costs, capital, operations and maintenance, and fuel costs of the new generation resources were calculated;
4. Using capacity size, gas management charges for a peaking facility in the area were estimated; and
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2014-2033) was calculated.

Table 70 summarizes the incremental capacity provided by this option as well as the total LMC of the Red Lake subsystem with this option, while Table 71 summarizes the cost of the option in the Red Lake subsystem.

Table 70: Capacity and LMC Summary for Generation Options at Red Lake

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Near-term Demand	Reference Forecast Near-term Demand	High Forecast Near-term Demand
NG Generation at Ear Falls (30 MW)	30 MW	91 MW	91 MW	91 MW	91 MW

Figure 25 illustrates the system state of the Red Lake subsystem with this option.

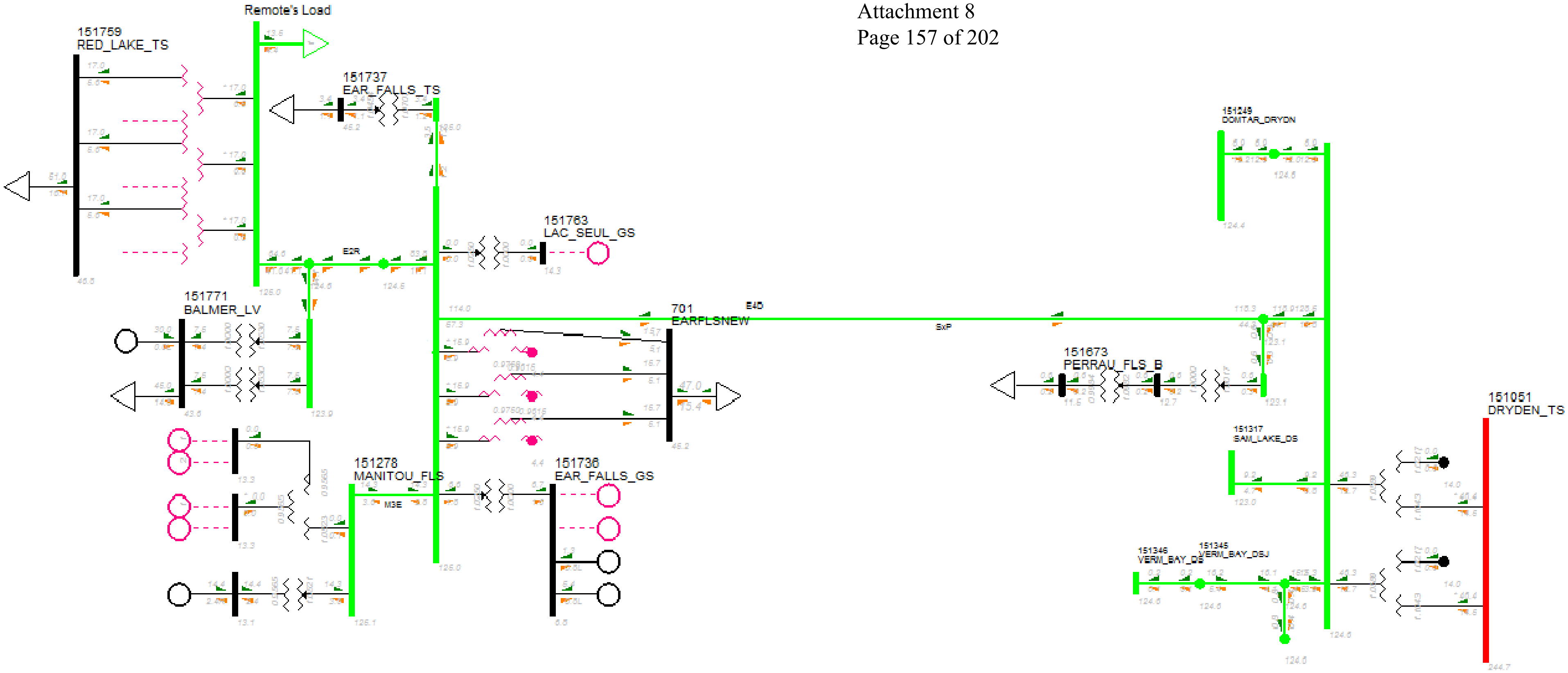
Table 71: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost		80.9																		
Fixed O&M		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Variable O&M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Avoided System Gen Cost		0.0	0.0	0.0	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6
Total Annual Gx Cost		82.7	1.8	1.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8
Levelized Annual Cost	0.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Annual Amortized cost	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Cumulative PV of Amortized cost	0.0	5.3	10.3	15.2	17.7	20.1	22.4	24.6	26.8	28.8	30.8	32.7	34.5	36.2	37.9	39.5	41.1	42.6	44.0	45.4

Table 72: Summary of Cost for Compensation Associated with 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost		8.1																		
O&M	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	8.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cumulative PV	0.0	0.4	0.9	1.3	1.7	2.0	2.4	2.7	3.1	3.4	3.7	4.0	4.3	4.6	4.8	5.1	5.3	5.6	5.8	6.0

Figure 25: 30 MW Generation Option Red Lake Subsystem Configuration



Given the existing opportunity for 30 MW of gas generation at Red Lake, a second gas generator at Ear Falls could be sized to serve the remaining capacity needs of the Red Lake subsystem. With a total of 60 MW of gas generation in the Red Lake subsystem, the LMC of the subsystem would increase by 60 MW to 190 MW (assuming all Pickle Lake subsystem load on E1C is transferred to the new line to Pickle Lake). Table 73 summarizes the capacity provided by a single 30 MW facility at Red Lake as well as two facilities in the subsystem.

Table 73: Summary of Incremental Capacity and LMC

Option	Incremental Capacity	Load Meeting Capability*	Low Forecast Long-term Demand	Reference Forecast Long-term Demand	High Forecast Long-term Demand
NG Generation at Ear Falls (30 MW)	30 MW	160 MW	100 MW	109 MW	136 MW
NG Generation at Ear Falls (60 MW)	60 MW	190 MW			

*Includes the capability of E4D and E2R after upgrading

Figure 25 and Figure 26, show the state of the Red Lake subsystem with each of these options implemented, while Table 74 to Table 77, provide a detailed summary of the costs for each option. The generators at Red Lake and/or Ear Falls help to maintain the voltages at those buses to a healthy range of 120 kV to 125 kV.

Table 74: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost																	80.9			
Fixed O&M																	1.8	1.8	1.8	1.8
Variable O&M																	0.0	0.0	0.0	0.0
Fuel Cost																	0.0	0.0	0.0	0.0
Avoided System Gen Cost																	-2.7	-2.7	-2.7	-2.7
Total Annual Gx Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.1	-0.9	-0.9	-0.9
Annual Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9	4.9	4.9	4.9
Cumulative PV of Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	2.3	3.4	4.4

Table 75: Summary of Cost for Compensation Associated with 30 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost																	14.1			
O&M																	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.2	0.1	0.1	0.1
Annual Amortized Cost																	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.8	1.2	1.6

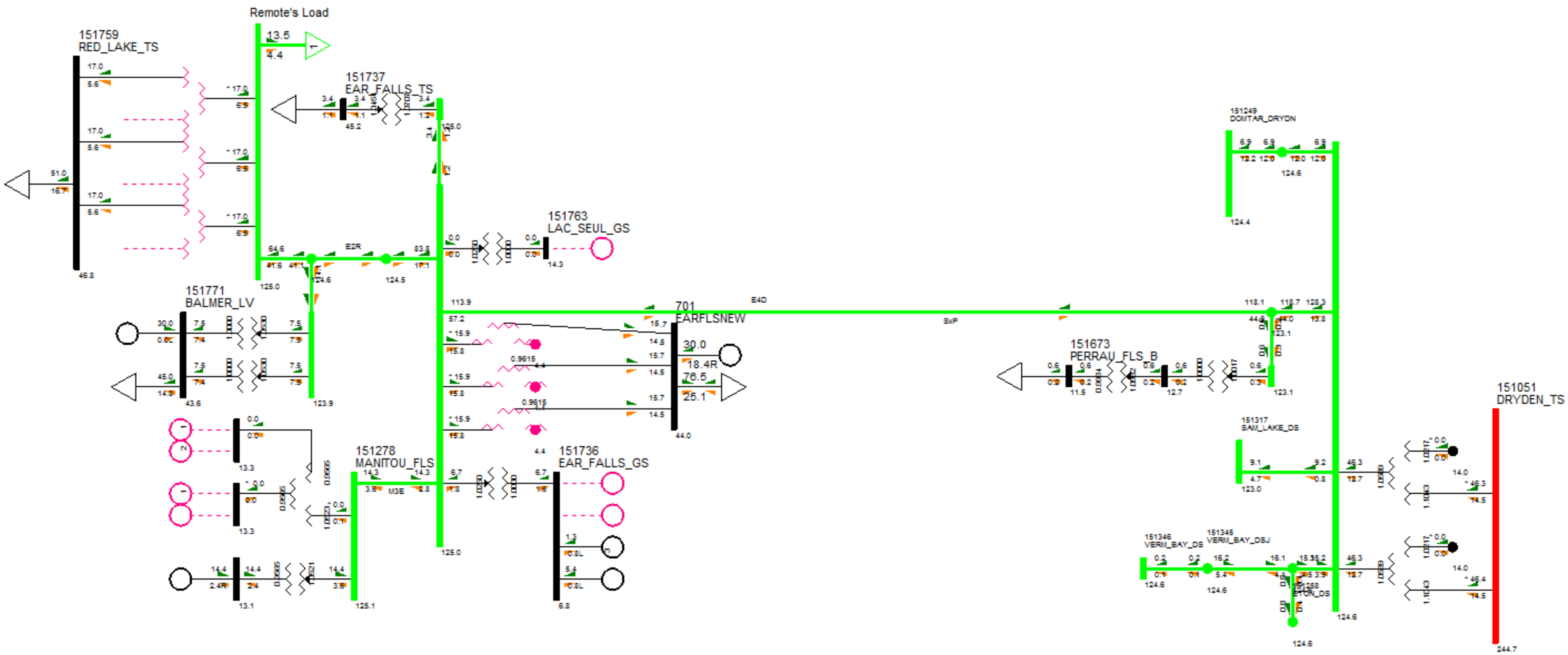
Table 76: Summary of Cost for 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost																	145.7			
Fixed O&M																	3.0	3.0	3.0	3.0
Variable O&M																	0.0	0.0	0.0	0.0
Fuel Cost																	0.0	0.0	0.0	0.0
Avoided System Gen Cost																	-4.9	-4.9	-4.9	-4.9
Total Annual Gx Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	143.8	-1.9	-1.9	-1.9
Annual Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.4	8.4	8.4	8.4
Cumulative PV of Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	3.7	5.5	7.2

Table 77: Summary of Cost for Compensation Associated with 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost																	6.9			
O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.1	0.1	0.1
Annual Amortized Cost																	0.4	0.4	0.4	0.4
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.8

Figure 26: 60 MW Generation Option Red Lake Subsystem Configuration



10.7.3 **Ring of Fire Subsystem Options**

Assumptions

The following assumptions were made to determine the infrastructure required to implement diesel and CNG fueled generation at the mine-sites and its costs. Based on the infrastructure requirements, costs for capital, operating and maintenance and capital sustainment were estimated to determine the total cost of generating electricity at Ring of Fire mine-sites. For both fuel options, generators are assumed to not be connected to the Ontario electricity system.

Assumptions for CNG Fueled Mine-site Generation:

- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed;
- CNG would be compressed at a new compressor station in the Nakina area and transported on specialized high pressure transport trailers via the proposed road to the mine-sites;
- Decanting stations near the generators would be required to decompress the natural gas for use;
- CNG fuel delivery would be on a just in time basis due to challenges and additional cost of large scale on-site CNG storage;
- If CNG is unavailable generators will run on diesel;
- A sufficient number of trailers would be required to both transport fuel as well as provide for some limited on-site storage to ensure a stable flow of fuel; and
- Discrete generator unit sizes of 9.5 MW.

Assumptions for Diesel Fueled Mine-site Generation:

- Generators will be diesel fueled reciprocating engines;

- Diesel would be supplied from the Thunder Bay area and transported to the mine-sites via the proposed all-weather road, stored on site and used for in-mine equipment as well as for electricity generation;
- On-site diesel storage is available due to the variety of uses for diesel at the mine-sites, therefore timing and logistic challenges with fuel transport and delivery will not be as significant as for CNG; and
- Discrete generator unit sizes of 9.5 MW.

Study Procedure

To estimate the cost of implementing a CNG or diesel electricity generation facility at the Ring of Fire mine-sites, the following procedure was undertaken:

1. Determine forecast peak load for the Ring of Fire mines based on the demand forecast;
2. Determine the required amount of generation capacity based on peak load;
3. Calculate the energy requirements (total kWh per year) by applying a estimated load factor to the peak load;
4. Calculate fuel required daily based on energy requirements;
5. Estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;
6. (CNG option only) Determine number of compressor and decanting stations based on amount of fuel required per day; and
7. Use the calculated values (generator capacity, number of trucks, annual fuel requirements, and decanting/compressing stations) to calculate initial capital costs, refurbishment costs, operation and maintenance costs, and fuel costs of the system.
8. These capital, operations and maintenance costs, were amortized over the project life and the present value over the planning period (2013-2033) was calculated.

Planning Level Assessment

The generation options considered for supplying the Ring of Fire subsystem would only supply the mining load. The five remote communities in the Ring of Fire subsystem have been determined to be economic to connect as per the findings of the Remote Community Connection Plan. Backup generation capacity is considered to use consistent reliability criteria specified under ORTAC. Table 78 outlines the generation solution options considered for the Ring of Fire subsystem mining demand.

Table 78: Summary of Incremental Capacity and LMC

Option	Incremental Capacity	Load Meeting Capability for Mining	Low Forecast Long-term Mining Demand	Reference Forecast Long-term Mining Demand	High Forecast Long-term Mining Demand
38 MW of CNG	22 MW	22 MW	0 MW	22 MW	66 MW
38 MW of Diesel	22 MW	22 MW			
57 MW of CNG	44 MW	44 MW			
57 MW of Diesel	44 MW	44 MW			
85.5 MW of CNG	71 MW	71 MW			
85.5 MW of Diesel	71 MW	71 MW			

Table 79 through Table 83 below summarize the cost profiles for each option.

Table 79: Summary of Cost for 38 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	39.8	0.0	0.0	0.0	1.8	0.0	0.0	0.0	1.8	0.0	24.7	0.0	1.8	0.0	0.0	0.0	1.8
O&M and Fuel	0.0	0.0	0.0	31.6	32.1	32.6	33.1	33.7	34.2	34.8	35.4	36.0	44.5	45.2	45.9	46.7	47.4	48.1	48.8	49.6
System Gen Credit	0.0	0.0	0.0	0.0	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Total Annual Gx Cost	0.0	0.0	0.0	71.4	23.8	24.3	24.8	27.1	25.9	26.5	27.0	29.5	36.1	61.5	37.6	40.1	39.1	39.8	40.4	43.1
Annual Amortized cost	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Cumulative PV of Amortized cost	0.0	0.0	0.0	31.1	61.0	89.7	117.3	143.9	169.5	194.0	217.7	240.4	262.2	283.2	303.4	322.8	341.5	359.4	376.7	393.3

Table 80: Summary of Cost for 57 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	58.8	0.0	0.0	0.0	3.0	0.0	0.0	0.0	3.0	0.0	37.1	0.0	3.6	0.0	0.0	0.0	3.6
O&M and Fuel	0.0	0.0	0.0	32.2	32.7	33.2	72.7	74.0	75.2	76.5	77.8	79.2	88.4	89.8	91.2	92.7	94.3	95.6	97.0	98.6
System Gen Credit	0.0	0.0	0.0	0.0	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Total Annual Gx Cost	0.0	0.0	0.0	91.0	15.9	16.4	55.9	60.2	58.4	59.7	61.0	65.4	71.6	110.0	74.4	79.5	77.5	78.8	80.2	85.4
Annual Amortized cost	0.0	0.0	0.0	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7
Cumulative PV of Amortized cost	0.0	0.0	0.0	53.1	104.1	153.2	200.4	245.8	289.4	331.4	371.7	410.5	447.8	483.7	518.1	551.3	583.2	613.8	643.3	671.7

Table 81: Summary of Cost for 85.5 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	87.3	0.0	0.0	0.0	4.8	0.0	0.0	0.0	4.8	0.0	55.6	0.0	5.4	0.0	0.0	0.0	5.4
O&M and Fuel	0.0	0.0	0.0	33.1	33.5	34.1	112.6	114.6	116.5	118.5	120.5	122.7	132.6	134.7	136.8	139.1	141.5	143.5	145.5	148.0
System Gen Credit	0.0	0.0	0.0	0.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0
Total Annual Gx Cost	0.0	0.0	0.0	120.4	6.5	7.1	85.6	92.4	89.5	91.5	93.5	100.5	105.6	163.3	109.8	117.5	114.5	116.5	118.5	126.4
Annual Amortized cost	0.0	0.0	0.0	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1
Cumulative PV of Amortized cost	0.0	0.0	0.0	74.8	146.7	215.9	282.3	346.3	407.7	466.9	523.7	578.3	630.9	681.4	730.0	776.7	821.6	864.8	906.3	946.3

Table 82: Summary of Cost for 38 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	65.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	8.0	0.0	24.7	0.0	10.4	0.0	0.0	0.0	10.4
O&M and Fuel	0.0	0.0	0.0	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	18.7	18.7	18.7	18.9	18.9	18.9	18.9	18.9
System Gen Credit	0.0	0.0	0.0	0.0	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Total Annual Gx Cost	0.0	0.0	0.0	80.7	7.4	7.4	7.4	15.4	7.4	7.4	7.4	15.4	10.4	35.1	10.4	20.9	10.5	10.5	10.5	20.9
Annual Amortized cost	0.0	0.0	0.0	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	16.5	32.4	47.7	62.4	76.6	90.2	103.2	115.8	127.9	139.5	150.7	161.4	171.7	181.7	191.2	200.4	209.2

Table 83: Summary of Cost for 57 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	93.5	0.0	0.0	0.0	18.4	0.0	0.0	0.0	18.4	0.0	37.1	0.0	20.0	0.0	0.0	0.0	20.0
O&M and Fuel	0.0	0.0	0.0	16.6	16.6	16.6	33.2	33.7	33.7	33.7	33.7	33.7	36.7	36.7	36.7	36.8	36.8	36.8	36.8	36.8
System Gen Credit	0.0	0.0	0.0	0.0	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Total Annual Gx Cost	0.0	0.0	0.0	110.1	-0.2	-0.2	16.4	35.3	16.9	16.9	16.9	35.3	19.9	57.0	19.9	40.0	20.0	20.0	20.0	40.0
Annual Amortized cost	0.0	0.0	0.0	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
Cumulative PV of Amortized cost	0.0	0.0	0.0	24.8	48.6	71.6	93.6	114.8	135.2	154.8	173.6	191.7	209.1	225.9	242.0	257.5	272.4	286.7	300.4	313.7

Table 84: Summary of Cost for 85.5 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	136.3	0.0	0.0	0.0	28.0	0.0	0.0	0.0	28.0	0.0	55.6	0.0	29.6	0.0	0.0	0.0	29.6
O&M and Fuel	0.0	0.0	0.0	17.9	17.9	17.9	51.1	52.1	52.1	52.1	52.1	52.1	55.1	55.1	55.1	55.2	55.2	55.2	55.2	55.2
System Gen Credit	0.0	0.0	0.0	0.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0
Total Annual Gx Cost	0.0	0.0	0.0	154.1	-9.1	-9.1	24.1	53.1	25.1	25.1	25.1	53.1	28.1	83.7	28.1	57.8	28.2	28.2	28.2	57.8
Annual Amortized cost	0.0	0.0	0.0	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1
Cumulative PV of Amortized cost	0.0	0.0	0.0	33.0	64.7	95.2	124.6	152.8	179.9	206.0	231.1	255.2	278.3	300.6	322.1	342.7	362.5	381.6	399.9	417.5

10.8 Transmission Options

Assumptions

In determining the cost of transmission options, the following were assumed:

- Unit cost estimates for new facilities were provided by a study conducted for the OPA by SNC Lavalin T&D. The report has been included in Section 11.3;
- Operations and maintenance costs were estimated as a percentage of the capital cost of the project, and would be incurred every year from the in-service date to the end of the projects useful life;
- Land cost was not included. Land costs are difficult to determine given the types of land and the variety of land holders that certain options described in this report may occupy; and
- Impact Benefit Agreements that may be negotiated between future projects proponents and impacted First Nations have not been estimated or included in the costs of options.

Procedure

To estimate the cost of transmission options to supply the North of Dryden sub-region, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to determine the capability of each option and the amount of capability of voltage control devices required to achieve the LMC;
2. Using unit costs for lines and stations, line lengths, number and types of new stations and/or station upgrades and voltage control requirements, capital, operations and maintenance costs of the system were calculated;
3. The amount of system generation that could be displaced after 2018, by associated local generation options for the subsystem was calculated; and
4. These capital, operations and maintenance costs and attributed costs for incremental system generation beginning in 2018, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

10.8.1 Red Lake Subsystem Transmission Options

Near-term Option - Upgrade of E4D and E2R

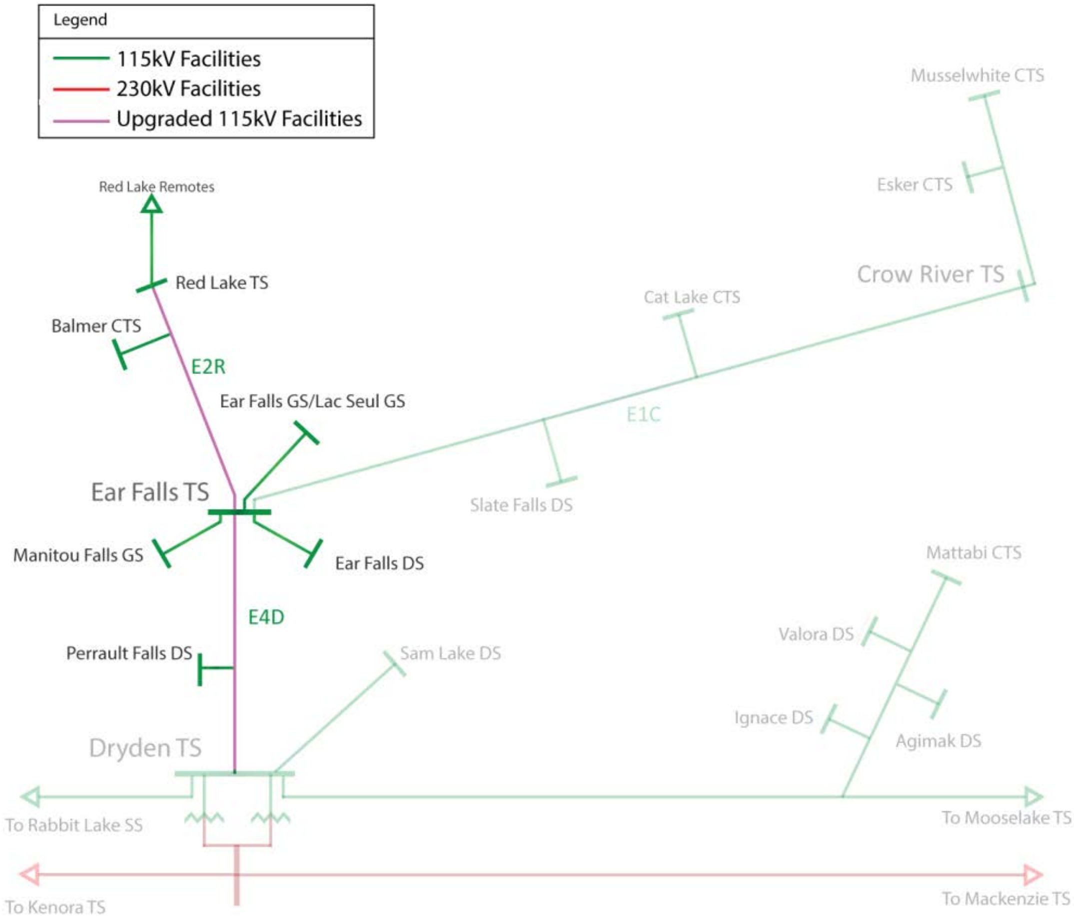
The existing lines serving the Red Lake subsystem are E4D, from Dryden to Ear Falls, and E2R, from Ear Falls to Red Lake. E4D has a thermal rating of 470 amps, and a transfer capability of 100 MVA (at 125 kV nominal voltage), while E2R a thermal rating of 420 amps, and a transfer capability of 91 MVA (125 kV nominal voltage). Based on dependable hydroelectric generation at Manitou Falls GS, Ear Falls GS and Lac Seul GS, and the current summer transmission line ratings, 85 MW of load can be served from Ear Falls TS. The Red Lake subsystem has an LMC of 61 MW, while the Pickle Lake subsystem has an LMC of 24 MW.

Hydro One has identified that E4D can be upgraded to a thermal rating of 670 amps, while E2R can be upgraded to 620 amps. After these line upgrades and the installation of an appropriate amount of voltage control at Ear Falls TS the Red Lake subsystem LMC will rise to 95 MW, assuming the Pickle Lake subsystem continues to be supplied solely from Ear Falls via circuit E1C and the LMC remains at 24 MW. A diagram of the upgrade of E4D and E2R is provided in Figure 27.

Table 85: Summary of Load Meeting Capability

<table>
<tr><th>Option</th><th>Incremental Capacity</th><th>Load Meeting Capability</th><th>Low Forecast Demand</th><th>Reference Forecast Demand</th><th>High Forecast Demand</th></tr>
<tr><td rowspan="2">Upgrade E4D and E2R
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>34 MW</td><td>95 MW</td><td rowspan="2">100 MW</td><td rowspan="2">109 MW</td><td rowspan="2">136 MW</td></tr>
<tr><td>35 MW</td><td>130 MW</td></tr>
</table>

Figure 27: E4D and E2R Upgrade Diagram

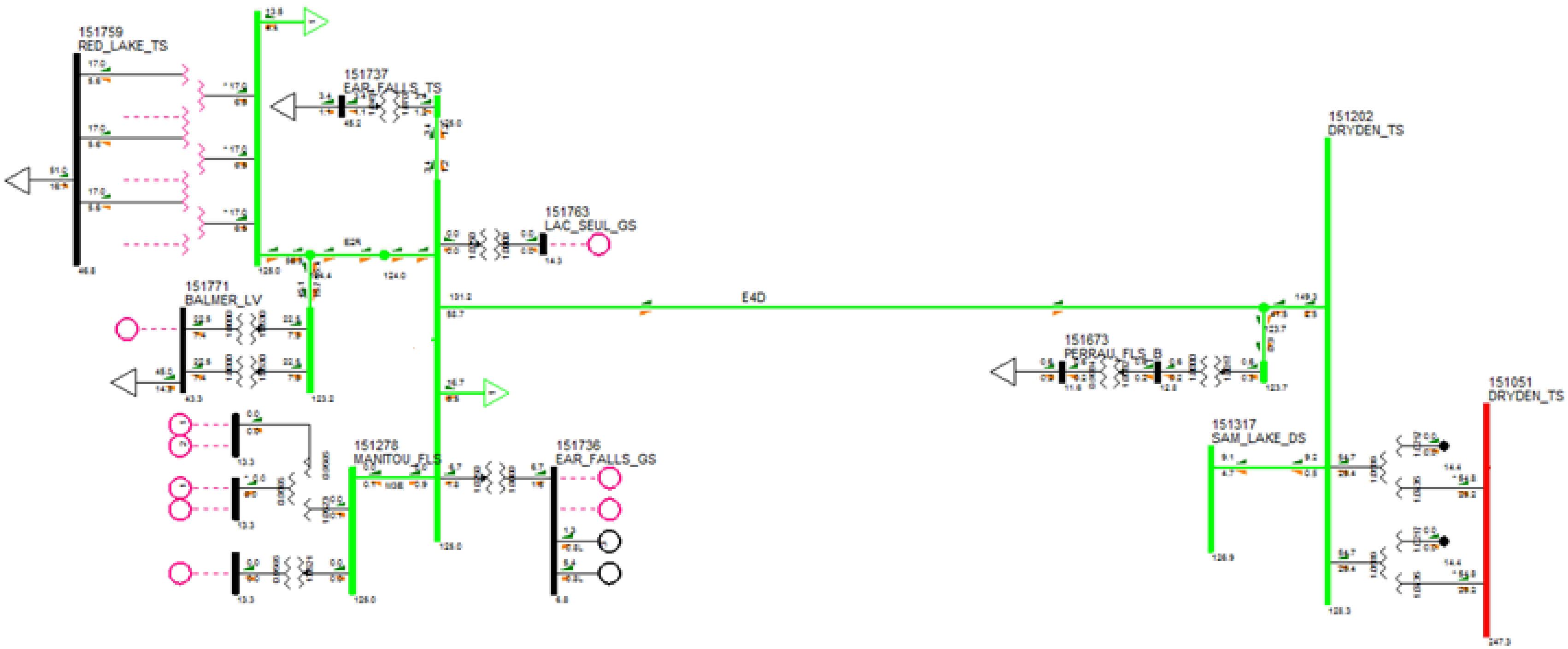


Hydro One has indicated that upgrading these lines as well as the installation of required voltage control devices could be completed within the near-term period. Table 86 below shows the cost breakdown of the upgrade option which includes the required voltage control devices. Figure 28 shows the load flow case during peak load. Ear Falls TS and Red Lake TS voltage is maintained in a healthy range of 120 kV to 125 kV.

Table 86: E4D and E2R Upgrade Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line Cost	0.0	5.0																		
Station Cost	0.0	10.5																		
O&M	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Annual Cost	0.0	15.7	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Annual Amortized Cost	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Cumulative PV	0.0	0.8	1.6	2.4	3.2	3.9	4.6	5.2	5.9	6.5	7.1	7.7	8.2	8.7	9.2	9.7	10.2	10.6	11.1	11.5

Figure 28: E4D and E2R Upgrade Red Lake Subsystem Configuration



Medium- and Long-term Option - 115 kV Line from Dryden TS to Ear Falls TS

This option is to build a new 115 kV single circuit line connecting at Dryden TS running to Ear Falls TS. A diagram of this option is provided in Figure 29. Because there are two local generation options for the Red Lake subsystem (30 MW, 60 MW), the 115 kV transmission option has been developed for an LMC of 160 MW and 190 MW. The option designed to have an LMC of 160 MW is comparable to the capability of the 30 MW Red Lake generation option and 190 MW LMC option is comparable to the 60 MW gas generation option, which meets the needs of the high scenario demand forecast. This difference in transmission LMC is determined by the voltage control requirements at Ear Falls TS.

Table 87: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 115 kV line from Dryden to Ear Falls with less compensation (160 MW)	30 MW	160 MW	100 MW	109 MW	136 MW
New 115 kV line from Dryden to Ear Falls with more compensation (190 MW)	60 MW	190 MW			

Figure 29: New 115 kV line to Ear Falls Diagram

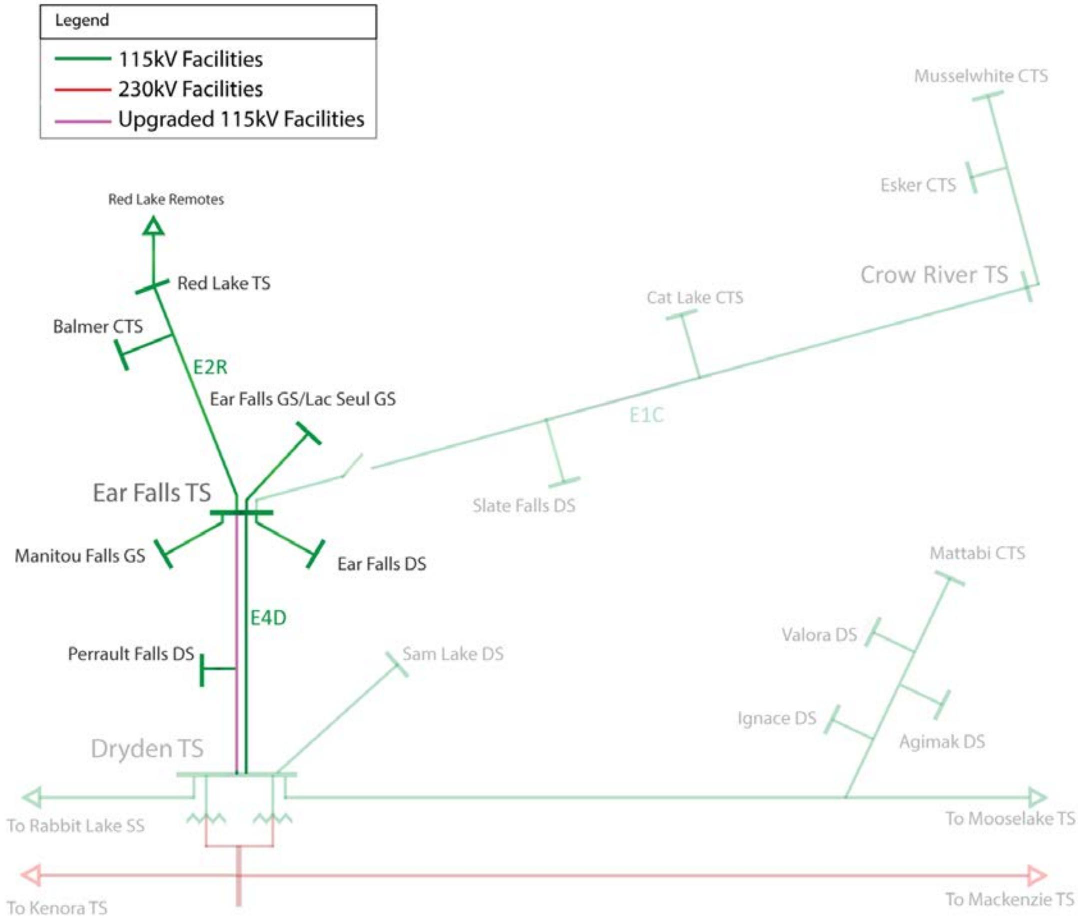


Figure 30, shows the peak load flow case for this option. Voltage at Ear Falls TS is maintained within a healthy range of 120 kV to 125 kV.

Table 88 and Table 89 summarize the annual cashflows and cumulative NPV cost for the options.

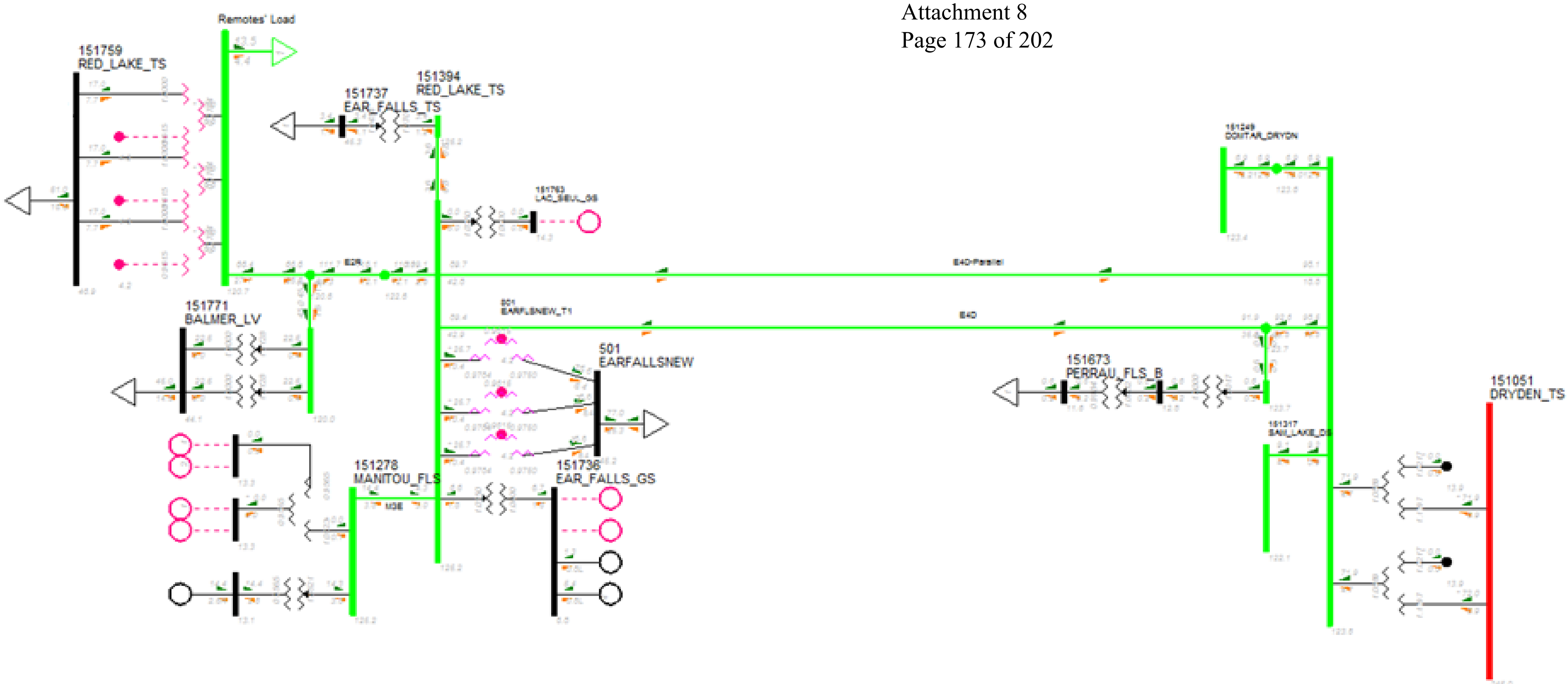
Table 88: 115 kV line to Ear Falls 160 MW LMC Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																	45.3			
Station cost																	45.6			
O&M																	0.9	0.9	0.9	0.9
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.8	0.9	0.9	0.9
Annual Amortized Cost																	5.1	5.1	5.1	5.1
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	5.4	7.9	10.3

Table 89: 115 kV line to Ear Falls 190 MW LMC Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																	45.3			
Station cost																	62.4			
O&M																	1.1	1.1	1.1	1.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	108.7	1.1	1.1	1.1
Annual Amortized Cost																	6.1	6.1	6.1	6.1
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	6.4	9.4	12.2

Figure 30: 115 kV Line Option Red Lake Subsystem Configuration



10.8.2 Pickle Lake Subsystem Transmission Options

The transmission options for the Pickle Lake subsystem include:

1. A new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker on the tap line and terminating at Crow River DS in Pickle Lake;

2. A new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker on the tap line and running to Pickle Lake terminating at Crow River DS or a new TS in the Pickle Lake area with a new 230/115 kV autotransformer at Crow River DS or a new station; and

3. A new single circuit line pre-built to 230 kV standards (230 kV structures, and hardware) and connecting it to M2D on the 115 kV system east of Dryden with an in-line breaker on the tap line. When additional capacity is required the line would be reterminated on the 230 kV system near Dryden (D26A) and a 230/115 kV autotransformer would be installed at Crow River DS or a new station in Pickle Lake.

For all of these transmission options, it is assumed that following the installation of a new line to Pickle Lake, the line E1C, connecting Ear Falls TS to Crow River DS (at Pickle Lake), would be normally open at Ear Falls. As a result, all customers in the Pickle Lake subsystem would be normally supplied by the new line to Pickle Lake. During sustained outages of the new line to Pickle Lake, some load in the Pickle Lake subsystem may be able to be restored by closing the normally E1C at Ear Falls TS and serving load in the Pickle Lake subsystem from Ear Falls TS. The amount of load that can be restored in the Pickle Lake subsystem from Ear Falls TS will be limited by the available capacity of circuits E4D and E1C.

115 kV Line to Pickle Lake

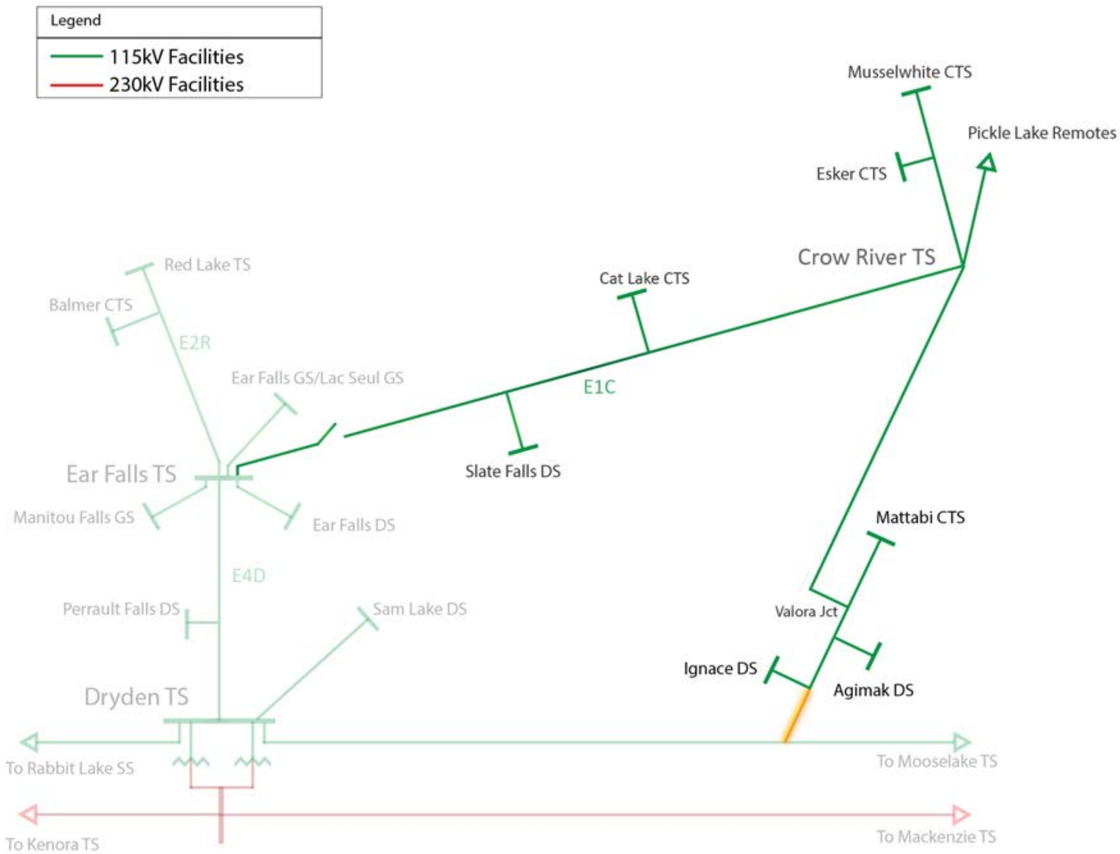
This option is to install a new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker and terminating at Crow River DS in Pickle Lake. Currently, there are a number of short sections of 29M1 between Ignace and Valora which have thermal ratings which are lower than the rest of the line. These sections will need to be upgraded to a thermal rating of at least 500 amps to allow the new line to Pickle Lake to have the required transfer capability.

Table 90: Summary of Load Meeting Capability

Option	**Incremental Capacity**	**Load Meeting Capability**	**Low Forecast Demand**	**Reference Forecast Demand**	**High Forecast Demand**
New 115 kV line from Valora to Pickle Lake	46 MW	70 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Figure 31 shows the Pickle Lake subsystem with this option, highlighting the section of 29M1 that would require upgrading.

Figure 31: New 115 kV line to Pickle Lake Diagram



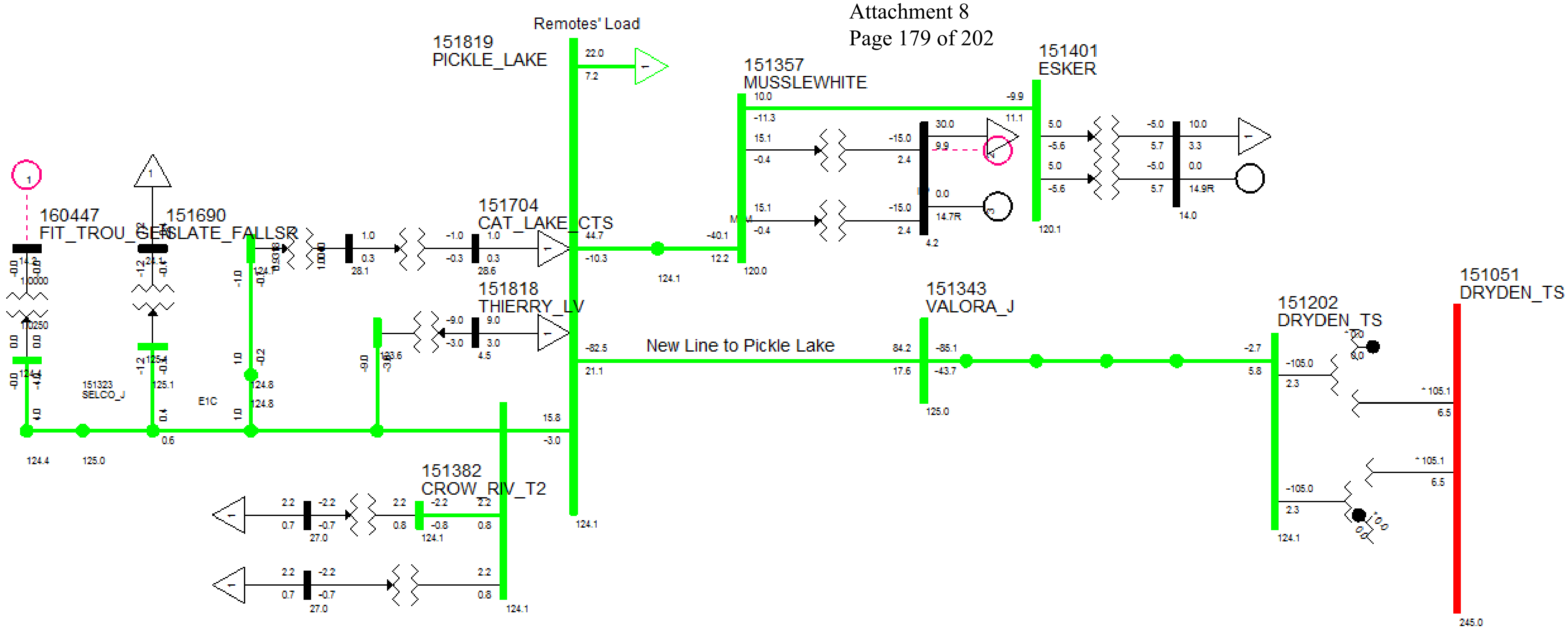
A summary of the cost for this option can be found in Table 91 below.

Figure 32 shows the load flow case during peak load. The Pickle Lake bus voltage is maintained in a healthy range of 120 kV to 125 kV.

Table 91: 115 kV line to Pickle Lake Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				104																
Station cost				22.5																
O&M				1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total Annual Cost	0.0	0.0	0.0	127.9	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Annual Amortized Cost				7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Cumulative PV	0.0	0.0	0.0	6.4	12.5	18.3	24.0	29.4	34.6	39.7	44.5	49.1	53.6	57.9	62.0	66.0	69.8	73.5	77.0	80.4

Figure 32: 115 kV Line Option Pickle Lake Subsystem Configuration



230 kV Line to Pickle Lake

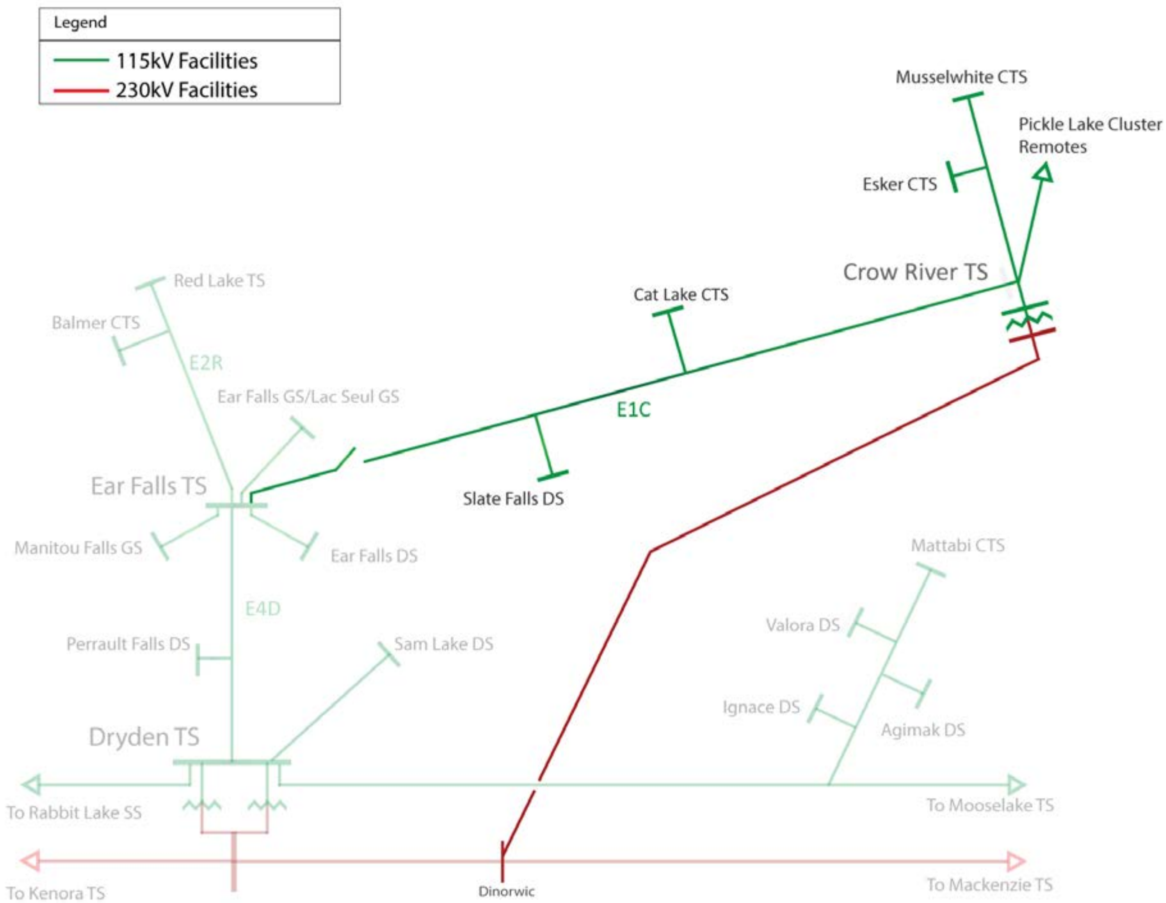
This option is to install a new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker running to Pickle Lake terminating at Crow River DS or at a new 230 kV station where a new 230/115 kV autotransformer will be installed.

Table 92: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 230 kV line from Dryden/Ignace to Pickle Lake	136 MW	160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

A diagram of this option is shown in Figure 33 below.

Figure 33: New 230 kV line to Pickle Lake Diagram



A summary of the cost for this option can be found in Table 93 and Table 94 below.

Table 94 shows an illustration of the peak load flow case for the new 230 kV line to Pickle Lake option. The voltage in the Pickle Lake area is maintained in a range of 240 kV to 245 kV, which helps to maintain voltages on existing and planned facilities within a healthy range.

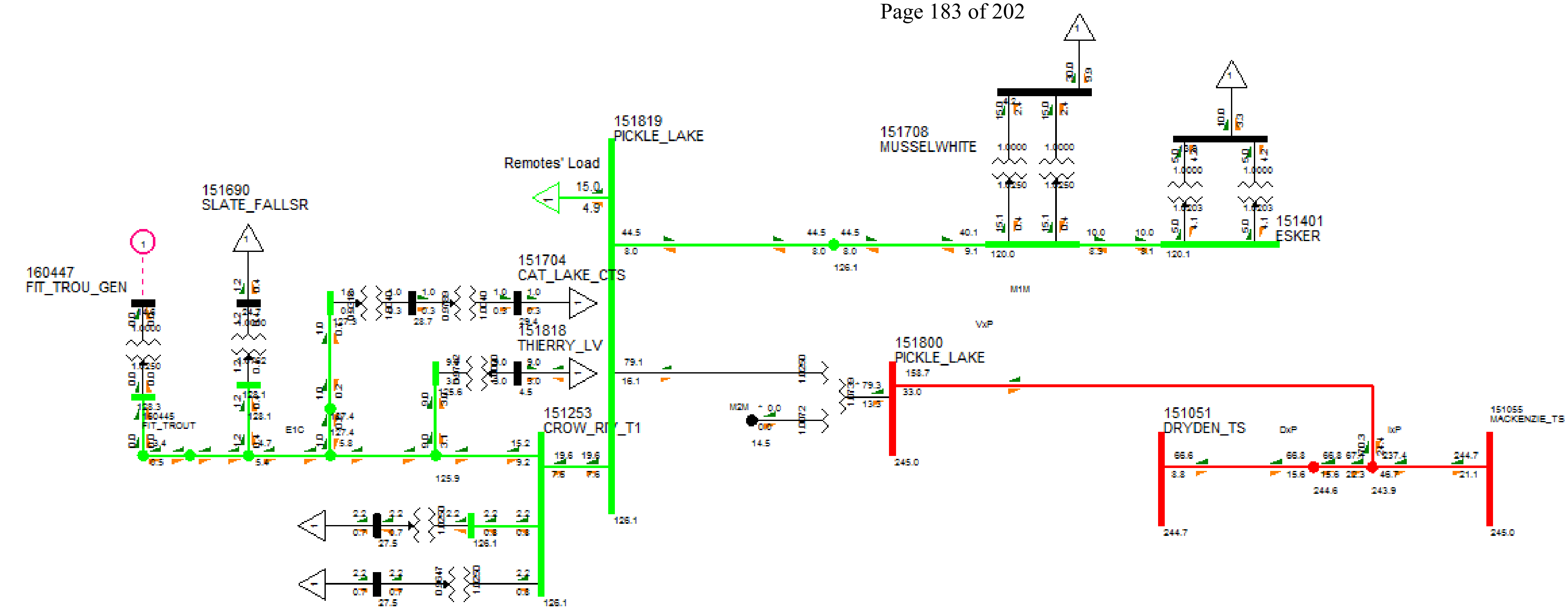
Table 93: 230 kV line to Pickle Lake Cost Summary for LMC up to 78 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				28.4																
O&M				1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Annual Cost	0.0	0.0	0.0	168.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Annual Amortized Cost				9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Cumulative PV	0.0	0.0	0.0	8.4	16.4	24.1	31.5	38.7	45.5	52.1	58.5	64.6	70.5	76.1	81.5	86.8	91.8	96.6	101.2	105.7

Table 94: 230 kV line to Pickle Lake Cost Summary for LMC up to 90 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				42.2																
O&M				1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Total Annual Cost	0.0	0.0	0.0	182.2	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Annual Amortized Cost				10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Cumulative PV	0.0	0.0	0.0	9.0	17.7	26.1	34.1	41.9	49.3	56.5	63.3	69.9	76.3	82.4	88.3	93.9	99.4	104.6	109.6	114.4

Figure 34: 230 kV Line Option Pickle Lake Subsystem Configuration



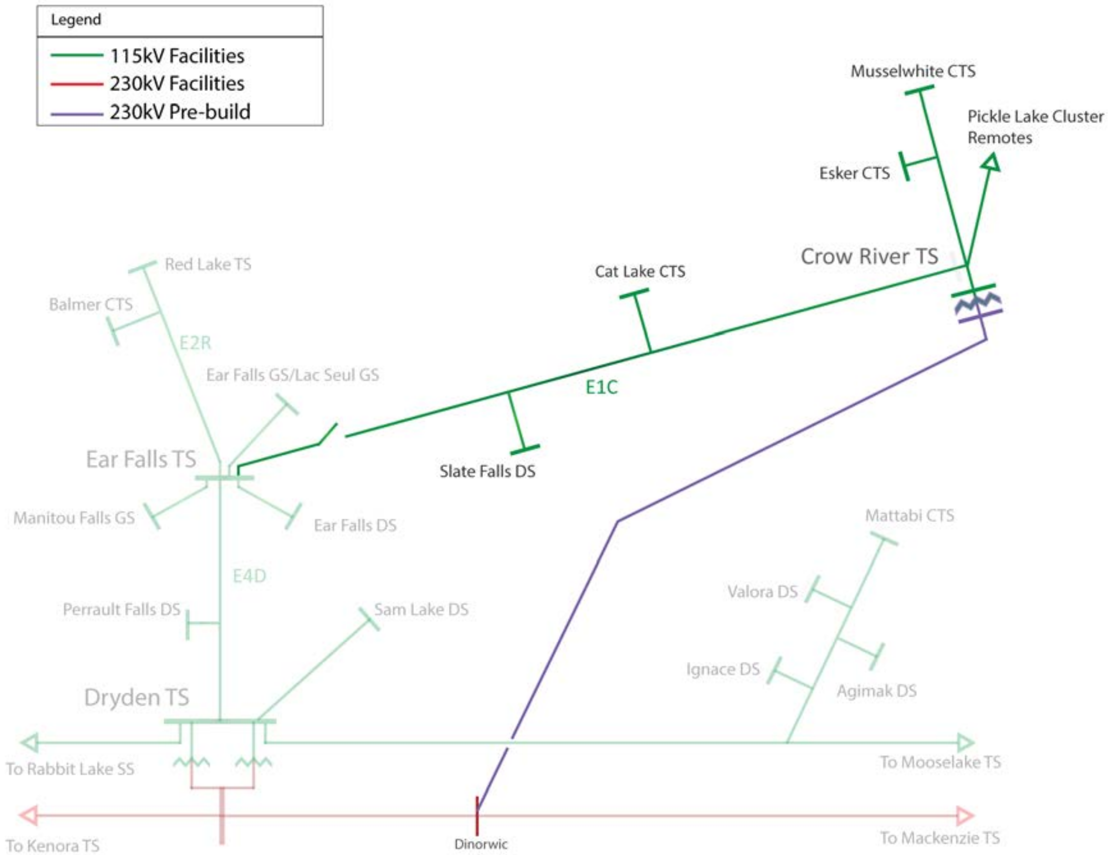
Pre-build 230 kV Line to Pickle Lake

This option would pre-build a new single circuit line to 230 kV standards (230 kV structures and hardware) and connect it to the 115 kV system on M2D east Dryden with an in-line breaker and running to Pickle Lake where it would terminate at Crow River DS. When additional capacity is required, the line would be reterminated on the regional 230 kV system (D26A) east of Dryden and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake.

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
Pre-build 230 kV line from Dryden/Ignace to Pickle Lake: Stage 1: operated at 115 kV Stage 2: operated at 230 kV	46 MW 90 MW	70 MW 160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Figure 35 provides a diagram of the area with this option, while Table 95 provides a summary of costs and timing for this option.

Figure 35: Pre-build 230 kV Line to Pickle Lake Option



Note: the above diagram illustrates the second stage configuration (operated at 230 kV).

Table 95: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 1

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				16.6																
O&M				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total Annual Cost	0.0	0.0	0.0	156.3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Annual Amortized Cost				8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Cumulative PV	0.0	0.0	0.0	7.8	15.2	22.4	29.3	35.9	42.3	48.4	54.3	60.0	65.5	70.7	75.8	80.6	85.3	89.7	94.1	98.2

Table 96: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 78 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost										14.0										
O&M										0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost										0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.1	1.6	2.1	2.6	3.0	3.5	3.9	4.3	4.7	5.1

Table 97: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 90 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost										26.0										
O&M										0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Annual Amortized Cost										1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0	3.9	4.8	5.6	6.4	7.2	8.0	8.7	9.4

10.8.3 Ring of Fire Subsystem Transmission Options

The following table summarizes the capability of various transmission options to meet the forecasted demand levels for the Ring of Fire sub-system for the reference, high, and low scenarios:

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
East-West corridor			7 MW	29 MW	73 MW
115 kV line from Pickle Lake	60 MW	60 MW			
230 kV line from Pickle Lake	78 MW	78 MW			
North-South corridor					
230 kV line from Marathon TS	78 MW	78 MW			
230 kV line from east of Nipigon	78 MW	78 MW			

The options and costs of the options are discussed in further detail below.

115 kV Line Connection for Ring of Fire Remote Communities from Pickle Lake

In a scenario where mines at the Ring of Fire do not connect to the transmission system, it has been assumed that the 5 remote communities in the Ring of Fire subsystem would develop a connection to Pickle Lake, based on the findings of the draft Remote Community Connection Plan. This option is to build a 115 kV line from Pickle Lake to a point near Webequie FN passing near Neskantaga FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would connect by distribution lines to a new transformer station near Neskantaga FN, while Nibinamik FN and Webequie FN would connect by distribution line to a transformer station near Webequie FN.

Figure 36, provides an illustrative schematic of this option, while costs are provided in Table 98.

Figure 36: 115 kV Line from Pickle Lake to Matawa Remotes

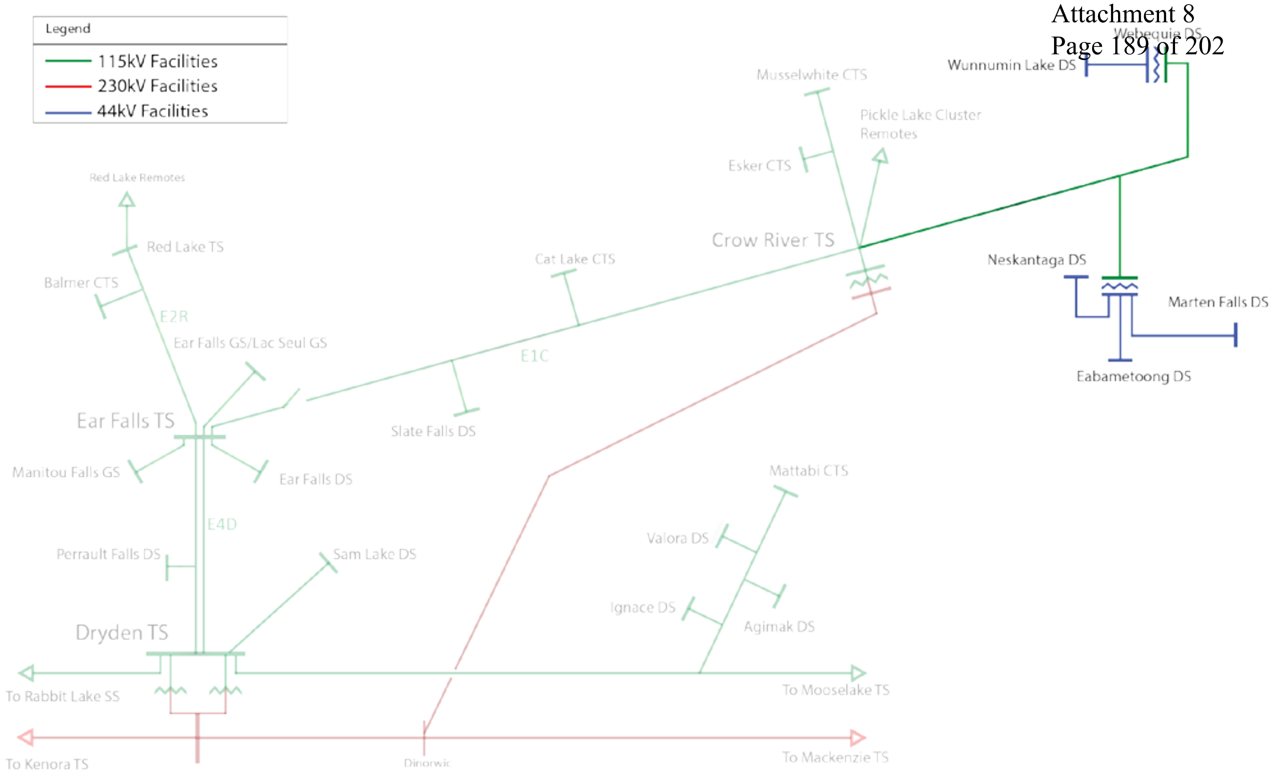


Table 98: 115 kV line from Pickle Lake to Ring of Fire Subsystem Remote Communities Cost Summary

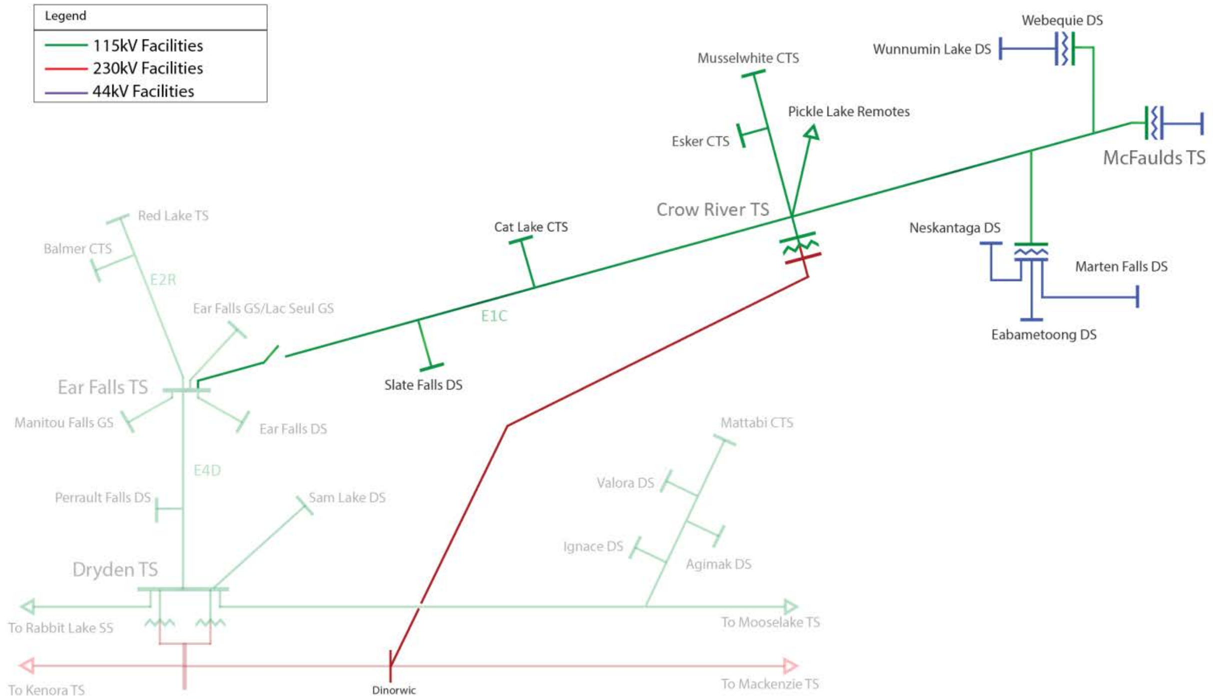
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						94.3														
Station cost						6.6														
O&M						1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	101.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Annual Amortized Cost						5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Cumulative PV	0.0	0.0	0.0	0.0	0.0	4.7	9.2	13.5	17.7	21.6	25.5	29.2	32.7	36.2	39.4	42.6	45.6	48.6	51.4	54.1
Line to Pickle Lake Portion	0.0	0.0	0.0	0.7	1.3	1.9	2.5	3.0	3.6	4.1	4.6	5.1	5.5	6.0	6.4	6.8	7.2	7.6	8.0	8.3
NPV with PL Line	62.4																			

115 kV Line from Pickle Lake to Ring of Fire

This option considers building a new 115 kV line from Pickle Lake to the Ring of Fire mining development area, and connecting the five remote communities in the Ring of Fire subsystem. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 60 MW of mining load at the Ring of Fire plus 7 MW of remote community load.

Figure 37, shows this option with the Pickle Lake subsystem.

Figure 37: 115 kV Line from Pickle Lake to Ring of Fire



A prorated portion of the costs for new a 230 kV transmission line and 230/115 kV transformer station from the Dryden area to Pickle Lake is included in the cost of this option because it is required for this option to be undertaken as is shown in the cost summary in Table 99.

Figure 38 provides the peak load flow for the North of Dryden sub-region, illustrating that voltages throughout the subsystem are maintained in a healthy range of 120 kV to 125 kV.

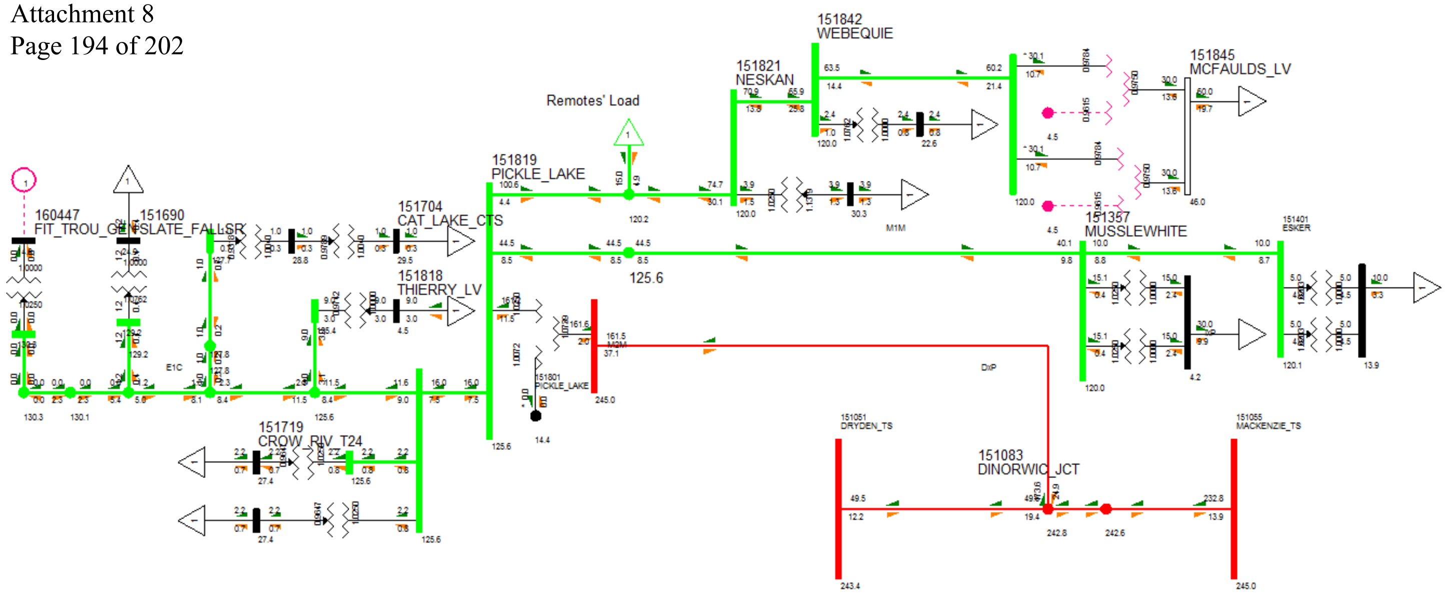
Table 99: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 29 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						132														
Station cost						13.6														
O&M						1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	147.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Annual Amortized Cost						8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Cumulative PV	0.0	0.0	0.0	0.0	0.0	6.8	13.3	19.5	25.5	31.3	36.9	42.2	47.4	52.3	57.1	61.6	66.0	70.3	74.3	78.2
Line to Pickle Lake Portion	0.0	0.0	0.0	2.2	4.3	6.3	8.2	10.1	11.9	13.6	15.3	16.9	18.4	19.9	21.3	22.7	24.0	25.2	26.4	27.6
NPV with PL Line	105.8																			

Table 100: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 51 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						132														
Station cost						23.2														
O&M						1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	157.1	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Annual Amortized Cost						8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	7.2	14.1	20.8	27.2	33.4	39.3	45.0	50.5	55.8	60.8	65.7	70.4	74.9	79.2	83.4
Line to Pickle Lake Portion	0.0	0.0	0.0	3.2	6.3	9.2	12.1	14.8	17.5	20.0	22.4	24.8	27.0	29.2	31.3	33.3	35.2	37.0	38.8	40.5
NPV with PL Line	123.9																			

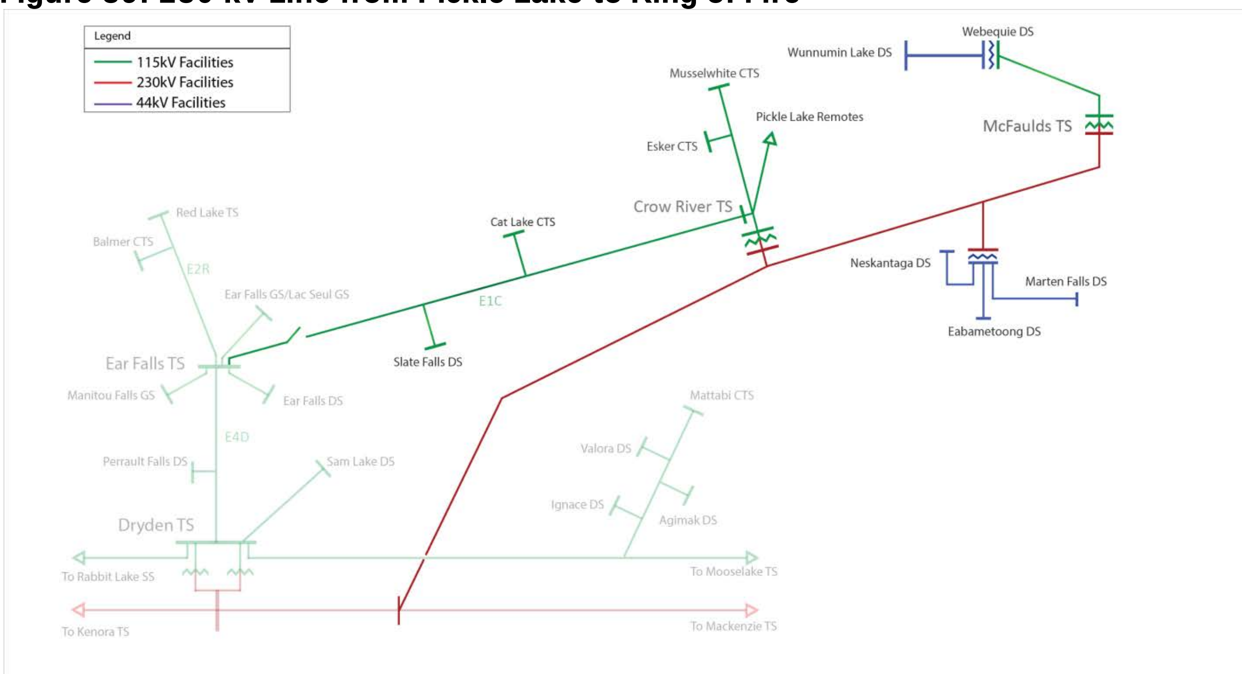
Figure 38: 115 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration



230 kV Line from Pickle Lake to Ring of Fire

This option considers building a new 230 kV single circuit line from a new 230 kV station at Pickle Lake to the Ring of Fire, and a new 230/115 kV TS near Neskantaga FN and at the Ring of Fire. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. This line would enable the connection of the five Matawa remote communities in the Ring of Fire subsystem as well as serve the high growth scenario (MW) for mining load at the Ring of Fire. Figure 39 shows the Pickle Lake and Ring of Fire subsystems with a new 230 kV line from the Dryden area to Pickle Lake and this option for a new 230 kV line from Pickle Lake to the Ring of Fire. Figure 39, shows this option implemented with the Pickle Lake subsystem.

Figure 39: 230 kV Line from Pickle Lake to Ring of Fire

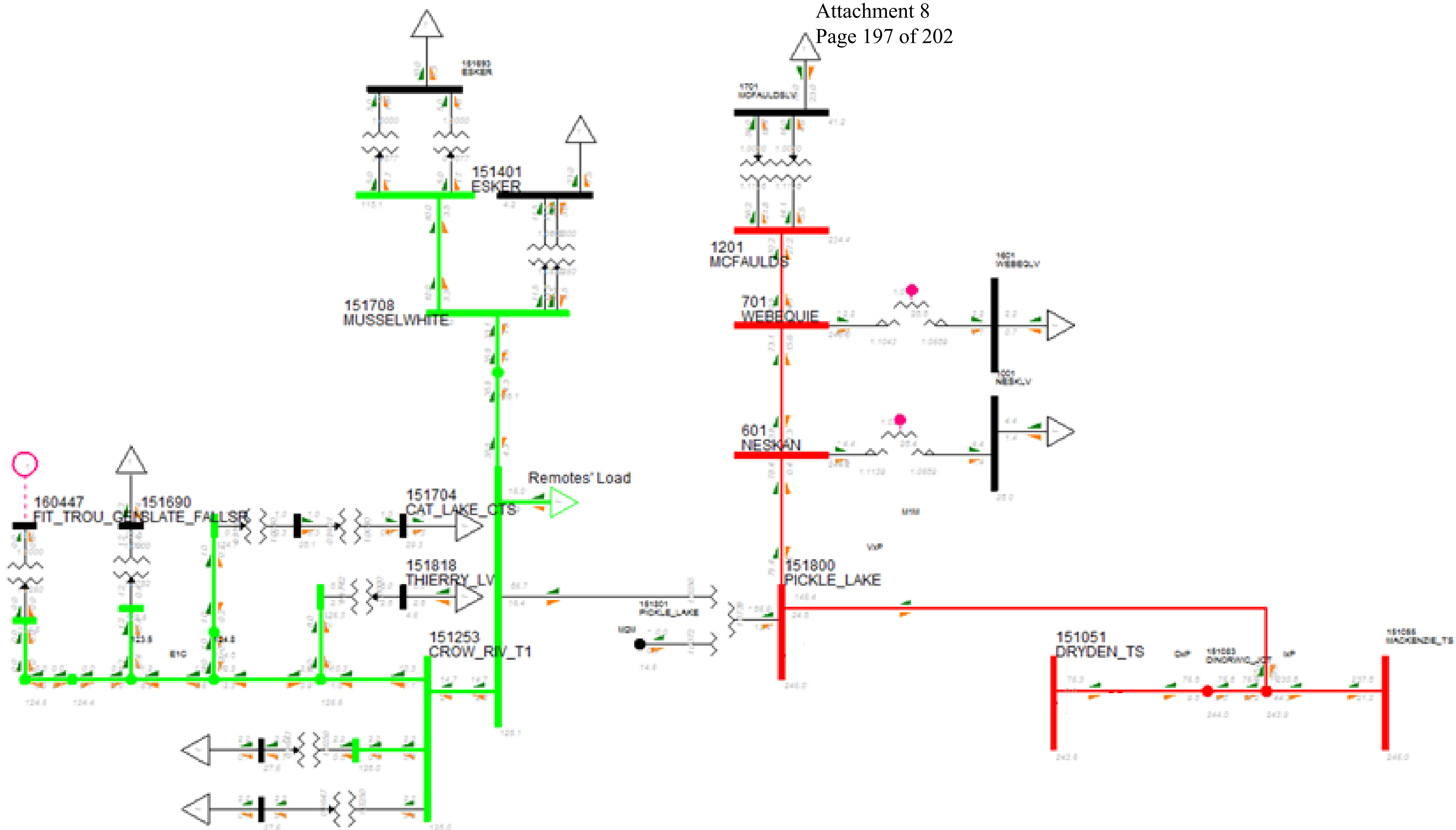


A prorated portion of the costs for new a 230 kV transmission line and station from the Dryden area to Pickle Lake is included in the cost of this option, as shown in the cost summary in Table 101 below.

Table 101: 230 kV line from Pickle Lake to Ring of Fire Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						165														
Station cost						30.4														
O&M						2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	197.7	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Annual Amortized Cost						11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Cumulative PV	0.0	0.0	0.0	0.0	0.0	9.1	17.8	26.2	34.3	42.0	49.5	56.6	63.5	70.2	76.5	82.7	88.6	94.2	99.7	104.9
Line to Pickle Lake Portion	0.0	0.0	0.0	4.1	8.0	11.8	15.4	18.9	22.2	25.4	28.5	31.5	34.4	37.1	39.7	42.3	44.7	47.1	49.4	51.5
NPV with PL Line	156.4																			

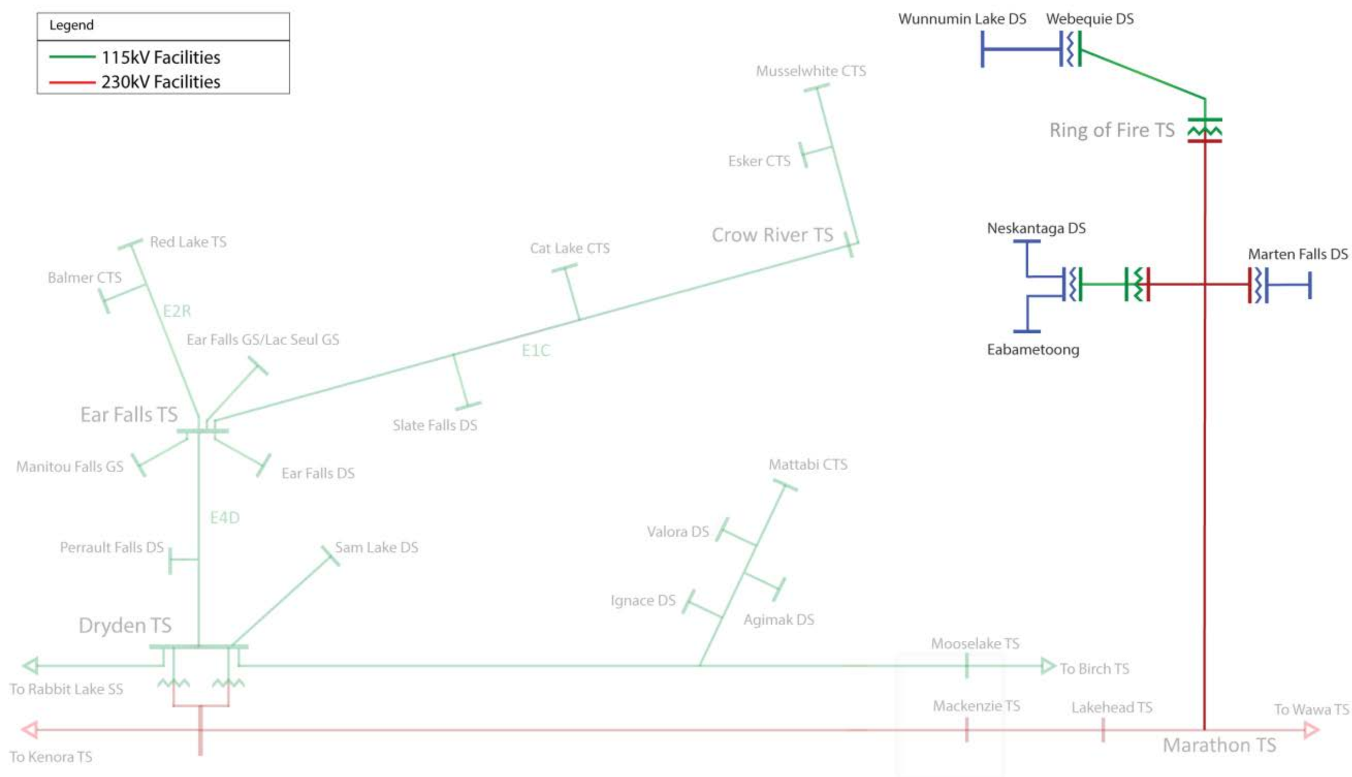
Figure 40: 230 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration



230 kV Line from Marathon TS or east of Nipigon to Ring of Fire

Given the potential for a new all season road to serve the Ring of Fire mining development area from around Nakina, this option was developed to leverage the availability of the all season road assuming they can share a common right of way from Nakina. The existing transmission supply serving the Long Lac\Nakina area is the single circuit 115 kV line A4L, which has insufficient capability to serve the forecast load growth of the Ring of Fire subsystem. Therefore, a new 230 kV single circuit transmission line from either Marathon TS or east of Nipigon would be required for this option. These options have similar line lengths and are expected to have approximately the same costs. A diagram of this option is provided in Figure 41 below.

Figure 41: 230 kV Line from Marathon or East of Nipigon to Ring of Fire

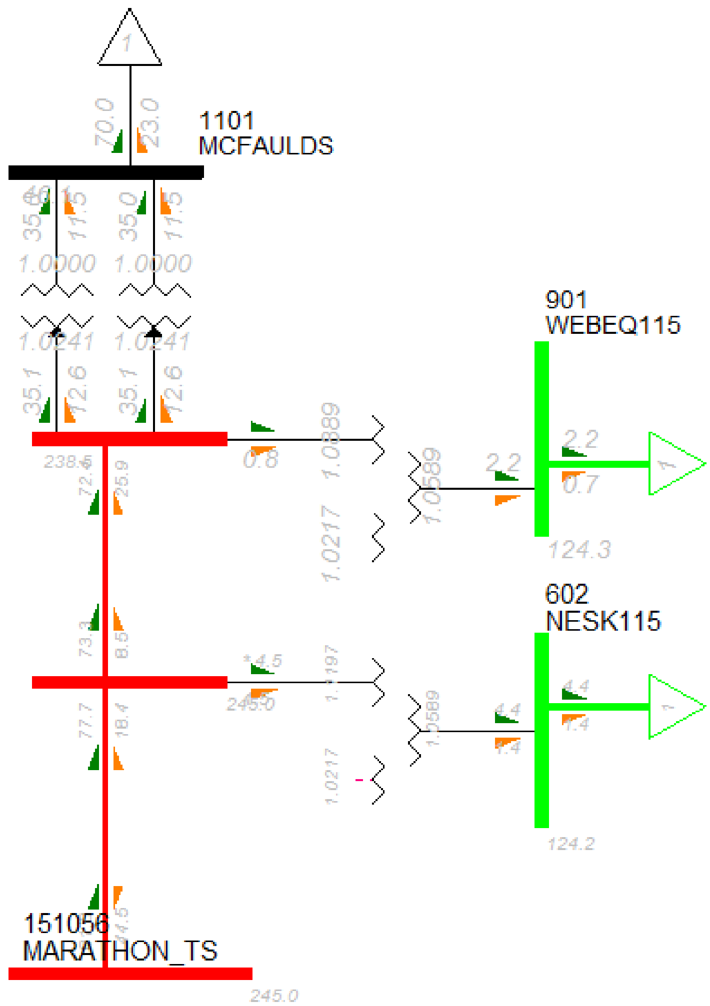


The LMC of the Ring of Fire subsystem for this option is 77 MW. This includes 7 MW for the communities on the line as well as 70 MW at the Ring of Fire. A summary of the cost for this option can be found in Table 102 below.

Table 102: 230 kV line from Marathon TS or east of Nipigon to Ring of Fire Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						262														
Station cost						64.7														
O&M						3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	330.0	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Annual Amortized Cost						18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Cumulative PV	0.0	0.0	0.0	0.0	0.0	15.1	29.7	43.7	57.2	70.1	82.6	94.6	106.1	117.1	127.8	138.0	147.9	157.3	166.4	175.2
NPV	175.2																			

Figure 42: 230 kV Line from Marathon Option Ring of Fire Subsystem Configuration



11 OTHER REPORTS PROVIDED

11.1 IESO/OPA North of Dryden and Remote Communities Study – May 2012

11.2 Draft Remote Community Connection Plan – August 2012

11.3 Unit Cost Estimates for Transmission Lines and Facilities in Northern Ontario and the Far North – SNC Lavalin T&D, 2011

11.4 Draft Remote Community Connection Plan – August 2014

Windsor-Essex

REGIONAL INFRASTRUCTURE PLAN

December 22, 2015

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Prepared and endorsed by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
E.L.K. Energy Inc.
Entegrus Powerlines Inc.
EnWin Utilities Ltd.
Essex Powerlines Corporation
Hydro One Networks Inc. (Distribution)

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional near and mid-term needs identified based on new and/or updated information provided by the RIP Working Group.

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

Working Group 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 RIP 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 RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP 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 RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

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

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)

This RIP provides a consolidated summary of needs and recommended plans for Windsor-Essex Region. No long-term needs (10 to 20 years) and associated plans have been identified.

This RIP is the final phase of the regional planning process and it follows the completion of the Windsor-Essex Region Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 [1].

The major infrastructure investments planned, or being planned, for the Windsor-Essex Region over the near and medium-term identified in the various phases of the regional planning process are given in the table below.

No.	Project	I/S Date	Cost
1*	Supply to Essex County Transmission Reinforcement (SECTR TX) Project	June 2018	$77.4M
2*	Supply to Essex County Transmission Reinforcement (SECTR DX) Project	June 2018	$19.3M
3	Replacement of Keith end-of-life autotransformers	2020	$45M
4	Replacement of Kingsville end-of-life transformers	2018	$12M
5	230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	2018	$63M
6	Additional feeder position at Malden TS	TBD	TBD
7	Decommission of Tilbury TS	2019	TBD
8	Decommission of T1 Transformer at Keith TS	TBD	TBD

* These projects address the needs identified in the Windsor-Essex IRRP study for the region in the near and medium-term.

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. Should there be any new needs that emerge due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") and documents the results of the joint study carried out by Hydro One, EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc. ("E.L.K Energy"), Entegrus Inc. ("Entegrus"), Hydro One Networks Inc. (Distribution) ("Hydro One Distribution), and the Independent Electricity System Operator ("IESO") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013.

The Windsor-Essex Region comprises the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. The map of the region is shown in Figure 1-1 below.

The Windsor-Essex area is supplied from a combination of generation located in the region and from the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations. The region peak electricity demand of about 800 MW is provided from three 230 kV and fourteen 115 kV step-down transformer stations.

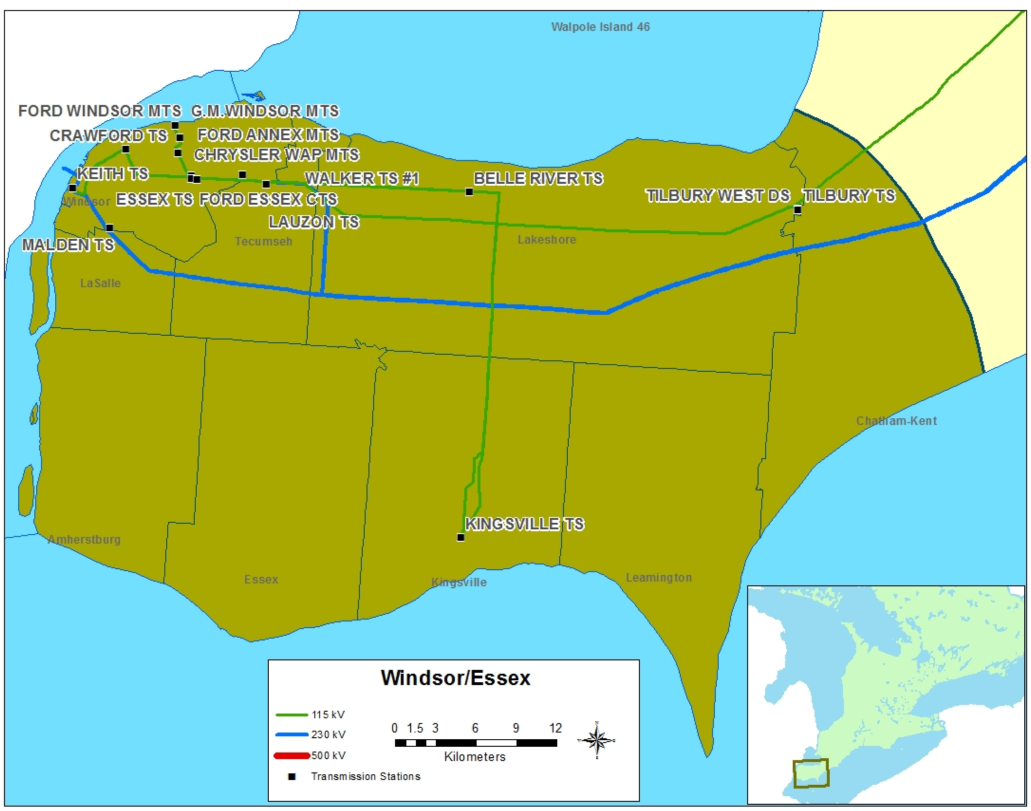

Figure 1-1 Geographical Map of Windsor-Essex Region

1.1 Scope and Objectives

This RIP report examines the needs in the Windsor-Essex Region. Its objectives are to: identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), Local Plan ("LP"), and/or Integrated Regional Resource Plan ("IRRP")); assess and develop wires plans to address these needs; provide the status of wires planning currently underway or completed for specific needs; and identify investments in transmission and distribution facilities or both that should be developed and implemented to meet the electricity infrastructure needs within the region.

Planning activities for the Windsor-Essex Region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete and the Windsor-Essex Region was identified as a "transitional" region. The planning status for the region was considered to be in the IRRP phase of the regional planning process. An IRRP for the region was completed in April 2015.

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (NA, SA, LP, and/or IRRP).
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Working Group.

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the region.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the regional needs.
- Section 7 provides a summary of regional plans.
- Section 8 provides summary of other projects.
- Section 9 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a

[1] Also referred to as Needs Screening

need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. Since the Windsor-Essex Region was in transition to the new regional planning process, the IESO led IRRP engagement for this region was initiated after the completion of the IRRP.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The regional planning process specifies a 20 year planning assessment period for the IRRP. The RIP focuses on the wires options and, given the forecast uncertainty and the fact that adequate time is available to identify and plan new wire facilities in subsequent planning cycles, a study period of 10 years is considered adequate for the RIP. The exception would be the case where major transmission infrastructure investments are required. In these cases the RIP would review and assess longer term needs and develop a longer term plan.

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

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- Participating in and conducting wires planning as part of the IRRP for the region.
- Working and planning connection capacity requirements with the LDCs.

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

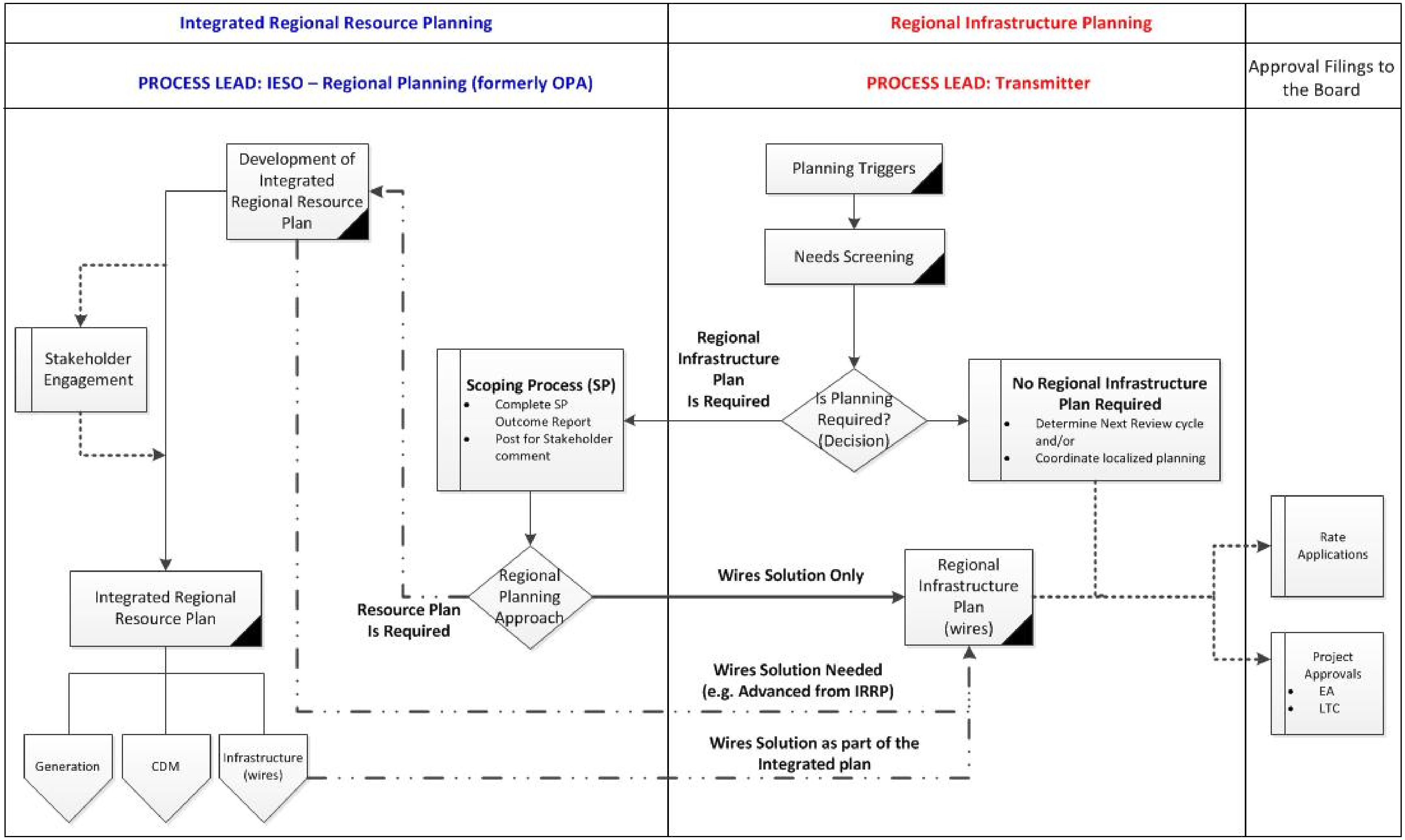

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP process is a four step process as shown in Figure 2-2 below.

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

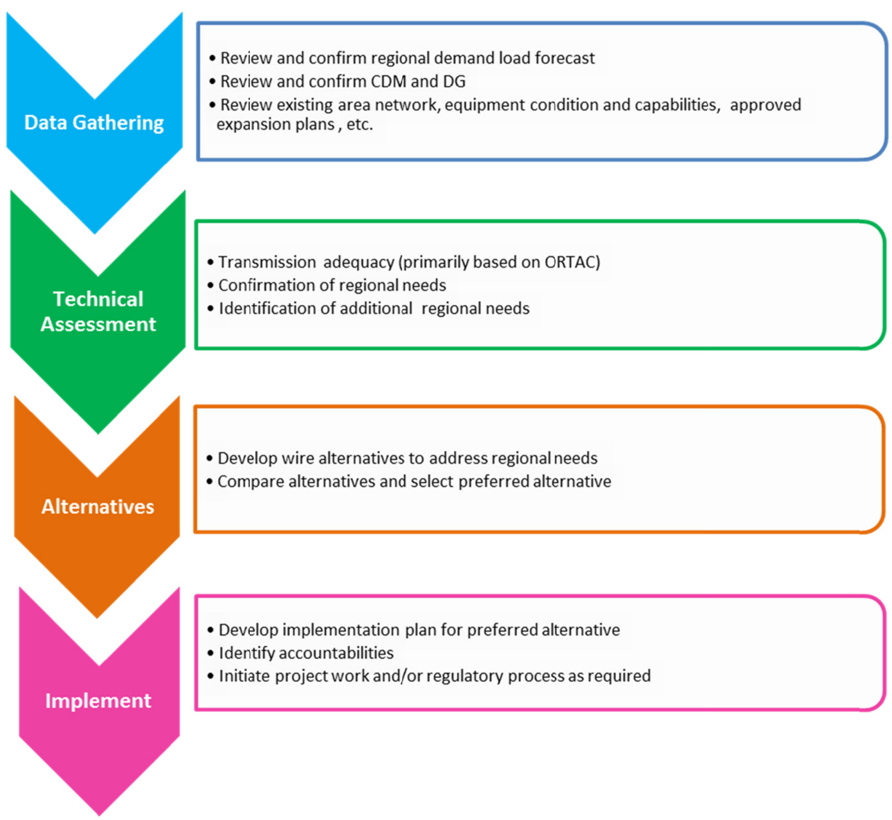

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE WINDSOR-ESSEX REGION COMPRISES THE CITY OF WINDSOR, TOWN OF AMHERSTBURG, TOWN OF ESSEX, TOWN OF KINGSVILLE, TOWN OF LAKESHORE, TOWN OF LASALLE, MUNICIPALITY OF LEAMINGTON, TOWN OF TECUMSEH, THE WESTERN PORTION OF THE MUNICIPALITY OF CHATHAM-KENT AND THE TOWNSHIP OF PELEE ISLAND.

The region is served by five LDCs: EnWin, Essex Powerlines Corporation, E.L.K. Energy, Entegrus, and Hydro One Distribution, whose service territories are shown in Figure 3-1. EnWin and Hydro One Distribution are directly connected to the transmission system, while the three other LDCs have low voltage connections.

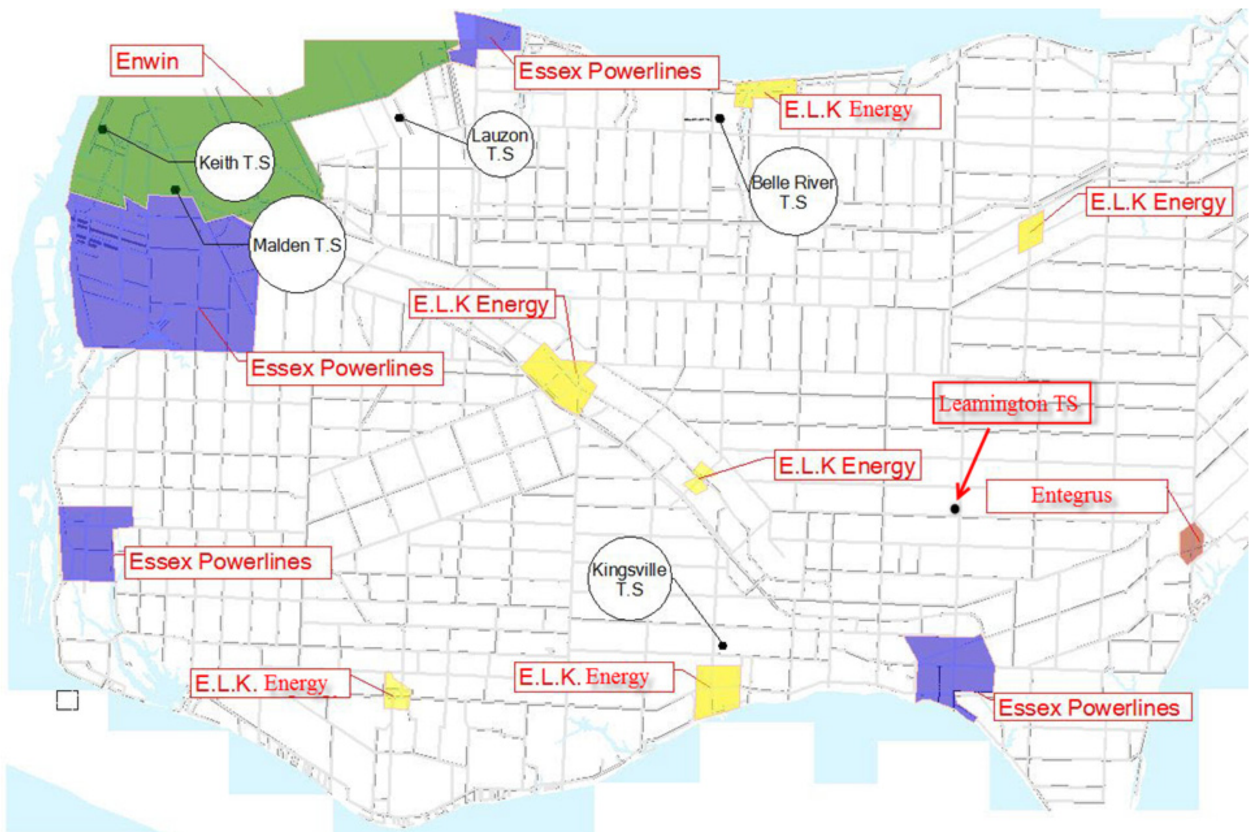

Figure 3-1 LDC Service Territories

The region peak electricity demand of about 800 MW is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 3-2 below.

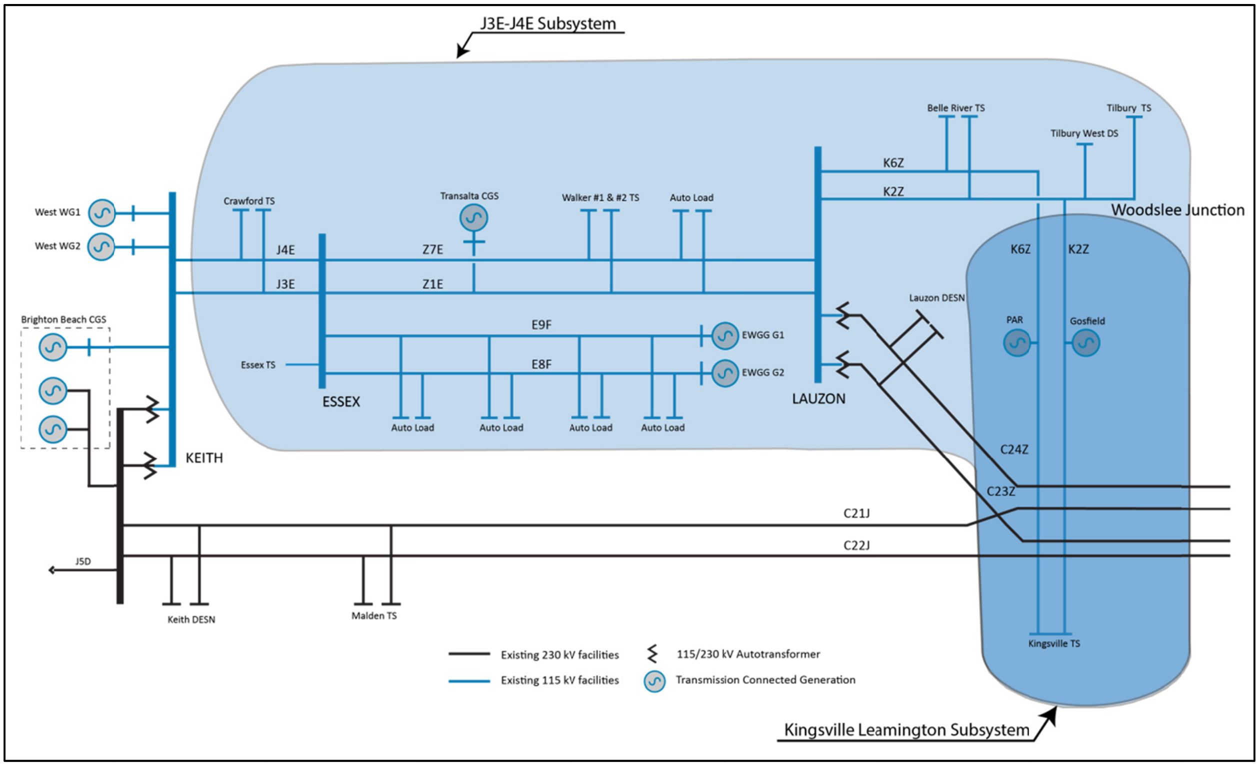

Figure 3-2 Windsor-Essex Area Subsystems/Single Line Diagram

The main transmission corridor in the region connects with the rest of the Hydro One system at Chatham Switching Station ("SS") and connects the Ontario transmission system with the Michigan transmission system at Keith TS.

The region's 115 kV network connects to the 230 kV transmission system at Keith TS and Lauzon TS via two auto-transformers in each station. About 65% of the area load is supplied by fourteen step-down transformers stations connected to the 115 kV network, while the balance is supplied by three step-down transformer stations connected to the 230 kV network. Table 3-1 lists the region's step-down transformer stations.

There are six customer-owned generating plants in the region connecting at the 230 kV and 115 kV levels with a combined contract capacity of 927 MW. In addition, the distributed generation connected at various locations to low-voltage ("LV") feeders in the region account for about 65 MW of effective capacity. Table 3-1 list the region's transmission connected generations.

The transmission system in the region can be divided into two “nested” sub-systems:

- The Kingsville-Leamington subsystem: customers supplied from Kingsville TS and
- The J3E-J4E subsystem: customers supplied from stations connected to the Windsor-Essex 115 kV system, as well as customers supplied from the 230/27.6 kV Lauzon DESN.

As can be noted in Figure 3-2 below, the Kingsville-Leamington subsystem is nested within the J3E-J4E subsystem. Therefore, increasing supply to the Kingsville-Leamington subsystem or transferring load from the existing Kingsville TS to a new 230 kV TS will impact the supply and demand balance in the J3E-J4E subsystem.

Table 3-1 Stations Included in the Windsor-Essex Region

Station (DESN)	Voltage Level (kV)	Supply Circuits	Connected Customer(s)
Belle River TS (T1/T2)	115/27.6	K2Z/K6Z	Hydro One Distribution
Kingsville TS (T1/T2/T3/T4)	115/27.6	K2Z/K6Z	E.L.K. Energy Essex Powerlines Corp. Hydro One Networks Inc.
Lauzon TS (T5/T6/T7/T8)	230/27.6	C23Z/C24Z	EnWin Utilities Ltd. Hydro One Distribution
Tilbury West DS	115/27.6	K2Z	Hydro One Distribution
Tilbury TS (T1)	115/27.6	K2Z	Hydro One Distribution
Chrysler WAP MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Crawford TS (T3/T4)	115/27.6	J3E/J4E	EnWin Utilities Ltd.
Essex TS (T5/T6)	115/27.6	Z7E/	EnWin Utilities Ltd.
Ford Annex MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Ford Essex CTS	115/13.8	Z1E/Z7E	EnWin Utilities Ltd.
Ford Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
G.M. Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Keith TS (T1)	115/27.6	C21J/C22J	Brighton Beach Power LP West Windsor Power EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Keith TS (T22/T23)	230/27.6	C21J/C22J	
Malden TS (T1/T2)	230/ 27.6	C21J/C22J	EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Walker MTS #2	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.
Walker TS #1 (T3/T4)	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.

Table 3-2 Transmission Connected Generation Facilities in the Region

Technology	Station Name	Contract Expiry Date	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generating Facility	Brighton Beach Power Station	Dec. 31, 2024	Keith TS	541	526
Combined Heat and Power (CHP)	West Windsor Power	May 31, 2031	J2N (Keith TS)	128	107
	TransAlta Windsor	Dec. 1, 2031	Z1E	74	74
	East Windsor Cogeneration Centre	Nov. 5, 2029	E8F/E9F	84	80
Renewables	Gosfield Wind Project	Jan. 12, 2029	K2Z	51	8
	Point Aux Roches Wind Farm	Dec. 5, 2031	K6Z	49	8

4. TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED OR ARE UNDERWAY BY HYDRO ONE, AIMED AT IMPROVING THE SUPPLY TO THE WINDSOR-ESSEX REGION. A BRIEF LISTING OF THE COMPLETED PROJECTS OVER THE LAST 10 YEARS IS GIVEN BELOW:

- Belle River TS (May 2006): Built a new 2-25/33/42 MVA 115/27.6 kV transformer station in the Town of Lakeshore supplied from 115 kV circuits K2Z/K6Z. The station provides additional load supply capability to meet the load requirements of Hydro One Distribution customers in the Town of Lakeshore. The connection of new station required the untwining of K6Z to obtain two circuits (K2Z and K6Z) with K6Z on the north side of the towers. The new K2Z circuit section which only extends to Belle River TS was then connected to the then existing K2Z circuit just outside of Lauzon TS.

- Essex TS (October 2008): The station was refurbished with new 2-50/66/83 MVA 115/27.6 kV transformers. The 115 kV supply circuits were reconfigured to mitigate exposure to customer load loss for loss of a single transmission element under certain system conditions.

- Malden TS: Transformer T2 75/100/125 230/27.6 kV was replaced (July 2010) and T1 was replaced (December 2011).

- Keith TS: T23 transformer 50/67/83 MVA 230/27.6 kV was replaced (October 2008) and T22 transformer 50/67/83 MVA 230/27.6 kV was replaced (December 2013).

- Walker TS #1: Reactor installation for short circuit mitigation (June 2011).

- Kingsville TS: Reactor installation for short circuit mitigation (November 2011).

- Keith TS: Reactor installation for short circuit mitigation (April 2012).

- Lauzon TS: Three breakers were replaced: SC2Q (June 2012), SC3E (April 2012) and SC4J (April 2012).

- Keith TS: Six breakers were replaced: SC11K (May 2014), SC11SC (May 2014), SC1B (June 2014), T11P (August 2014), T12P (October 2014), SC2Y (January 2015).

The following projects are currently underway:

- Crawford TS: is a 115/28 kV, with two 50/67/83 MVA units in Windsor. It supplies the downtown Windsor area with a current peak load of 60 MW. The existing T3 transformer is at the end-of-life with leaky fittings and headboard. The T3 fire suppression system and separation wall also needs to be upgraded to current standards. The current plan is to replace T3 transformer and install neutral grounding reactors on the T3 and T4 transformer units. The project includes protection and control upgrades and relocation of battery, necessary spill containment facilities at Crawford TS. The project is under execution for $8.46 million with an in-service date of December 15, 2016. There are no cost implications for the LDCs. Once this project is complete the station will meet the current design standards.

5. LOAD FORECAST AND OTHER ASSUMPTIONS

THE FORECASTS REFLECT THE EXPECTED PEAK DEMAND AT EACH STATION UNDER EXTREME WEATHER CONDITIONS, BASED ON FACTORS SUCH AS POPULATION, HOUSEHOLD AND ECONOMIC GROWTH, CONSISTENT WITH MUNICIPAL PLANNING ASSUMPTIONS.

5.1 Historical Demand

The peak demand in the Windsor-Essex Region has declined from a high of 1060 MW in the summer of 2006 to approximately 800 MW in both 2013 and 2014.

Figure 5-1 shows the historical summer peak demand observed in the region from 2004 to 2014. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a dip in 2008 and 2009 shows the area's response to the global recession. There is a large concentration of automotive manufacturing facilities in the City of Windsor. The sector is a major economic driver and electricity user within the region. The decline in Ontario's manufacturing sector and the 2008/09 economic downturn have both contributed to a decline in electricity use in the region.

While the manufacturing sector continues to face challenges in recovering, economic diversification is changing the region's growth and electricity use. The five-year Windsor-Essex Regional Economic Roadmap, released in 2011, identifies nine industry groups that hold growth potential for the region, including advanced manufacturing, tourism, and agri-business.

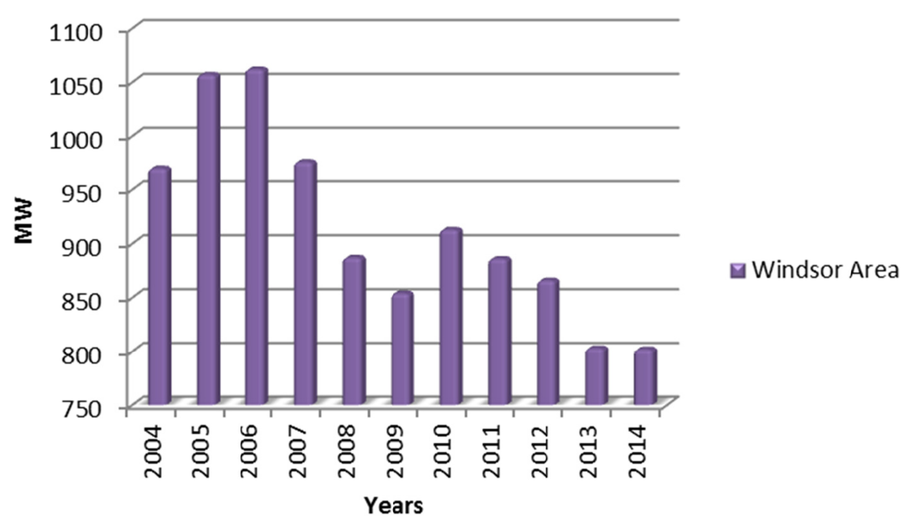

Figure 5-1 Historical Load Demand in Windsor-Essex Region

The peak demand in the Kingsville-Leamington area has also experienced fluctuations over the 2004-2014 period as shown in Figure 6-1.

5.2 Contribution of CDM and DG

In developing the planning forecast, the following process was used to assess the Windsor-Essex Region:

a) First, "gross demand" is established. Gross demand reflects the forecast developed and provided by the area LDCs and is influenced by a number of factors such as economic, household and population growth.
b) Second, "net demand" is derived by reducing the gross demand by expected savings from improved building codes and equipment standards, customer response to time-of-use pricing, and projected province-wide CDM programs. This information is provided by the IESO.
c) Lastly, a "planning forecast" is determined by reducing net demand by the contribution in the area from existing, committed and forecast DG. This information is provided by the IESO.

5.3 Gross and Net Demand Forecast

Summer peak gross non-coincident demand forecasts for the 20-year planning horizon were provided by EnWin and Hydro One Distribution, the two LDCs which are directly connected to the transmission system, for each of the transformer stations in the area. The forecasts from Hydro One Distribution include forecasts provided by the appropriate embedded LDCs.

The development of the load forecast for this RIP report followed a two-stage process:

(a) Using the forecast provided by the LDCs, the year by year growth rate for each station was first developed.
(b) The 2014 summer actual peak load, corrected for extreme weather, for each station was obtained.
(c) The growth rates from (a) were then applied to the 2014 summer peak load of (b) to obtain the gross load forecast for each station for extreme weather conditions.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. This load forecast reflects the following:

- A shift of load, commencing in 2016, from Walker TS #1 and #2 to Essex TS and GM MTS.
- Reduction in Kingsville TS load.
- Increase in loads at Keith TS, Crawford TS and Lauzon TS.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. Figure 5-2 is a graph of the Windsor – Essex Region extreme weather peak summer non-coincident load forecast. The overall region will experience an average annual growth rate of just less than 1%, while the Kingsville-Leamington area average growth rate would be about 1.6%.

Figure 5-2 also shows the load forecast from the IRRP report. The two forecasts are not materially different; hence the load forecast in this RIP report will not alter the conclusions of the IRRP.

The Reference Planning forecast (Appendix D) for each station is obtained by reducing the gross load forecast for the station by the amount of forecast conservation and DG. The conservation forecast (Appendix B) and the DG forecast (Appendix C) are the same as used in the IRRP report.

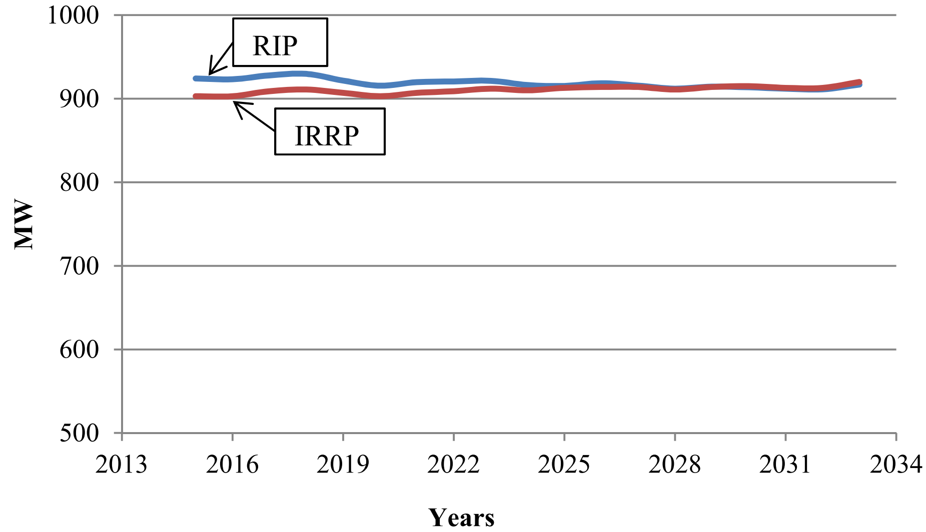

Figure 5-2 Reference Forecast in Windsor-Essex Region

5.4 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity. Load is assumed at 90% lagging power factor, unless known.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.

6. REGIONAL NEEDS

THIS SECTION SUMMARIZES THE WINDSOR-ESSEX REGION NEEDS OVER THE NEAR AND MID TERM. NO LONG TERM NEEDS HAVE BEEN IDENTIFIED.

Earlier studies by the IESO, ("Windsor-Essex Region Integrated Regional Resource Plan" - April 28, 2015, Supply to Essex County Transmission Reinforcement Project, January 2014) identified two near-term needs in the region. These needs are:

- **Minimize the Impact of Supply Interruptions in the J3E-J4E Subsystem:**
  The existing system lacks the capability to restore power to customers in the J3E-J4E subsystem in accordance with the ORTAC criteria, i.e., restoration of all loads within 8 hours. Based on current and forecast demand, up to 170 MW 0f the load interrupted cannot be restored by 2017.

- **Additional Supply Capacity in the Kingsville-Leamington Area:**
  Demand in the Kingsville-Leamington subsystem has already exceeded the load meeting capability of 120 MW in recent 3 years and is expected to continue to exceed the supply capacity over the forecast period. Figure 6-1 below shows the historical and forecast demand and supply capabilities in the Kingsville-Leamington subsystem after conservation and DG are taken into consideration.

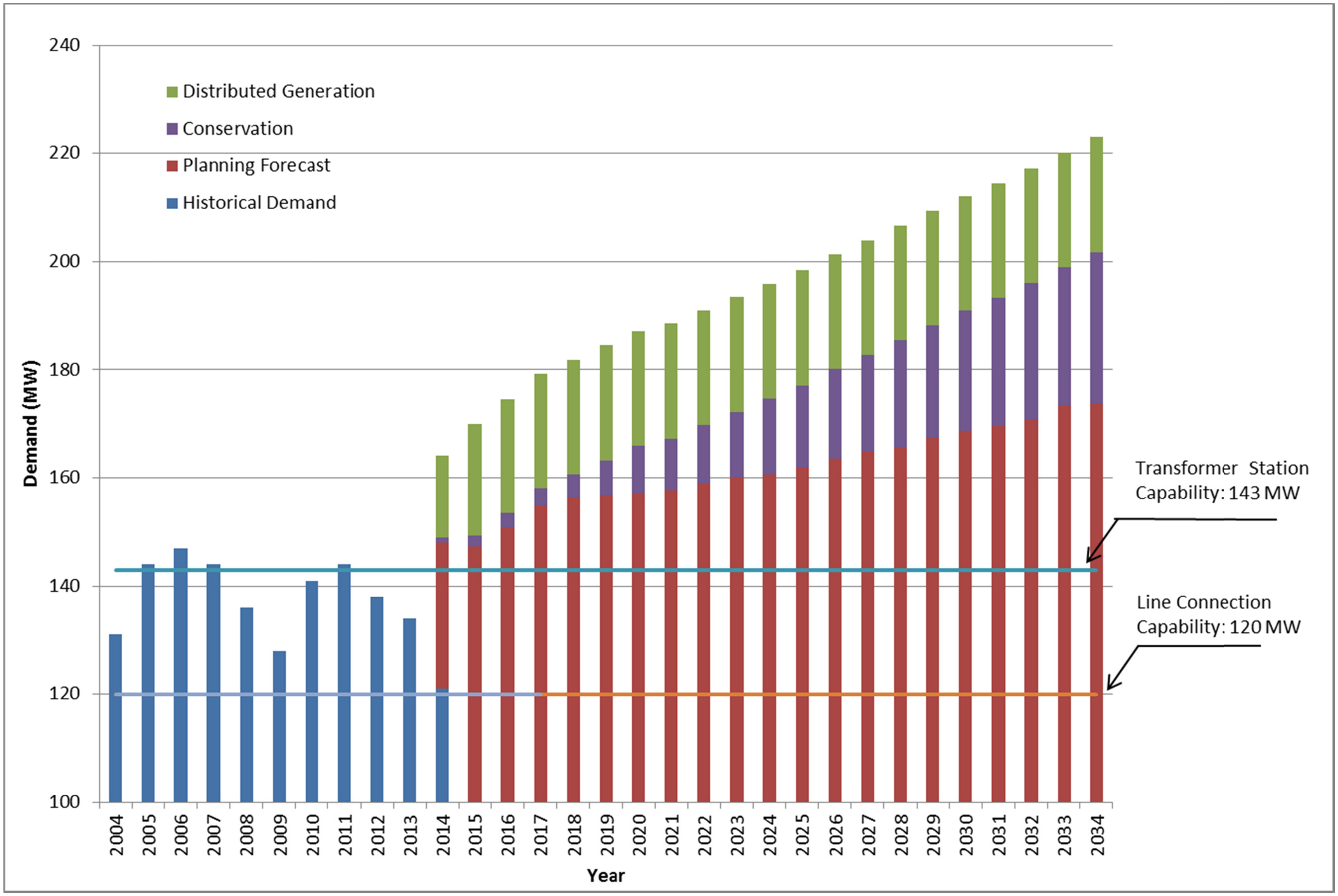

Figure 6-1 Historical and Forecast Demand of Kingsville-Leamington Subsystem

In addition, Hydro One has also identified infrastructure and major equipment which need replacement during the study period. The current plan is essentially a like-for-like replacement of 3 step-down transformers at Kingsville TS and 2 auto-transformers at Keith TS.

These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

Table 6-1 Summary of Needs

Type	Needs	Timeline	Process
Capacity to Meet Demand	Kingsville-Leamington Subsystem	2018	**IRRP**
Minimize the Impact of Interruption	J3E-J4E Subsystem	2018	**IRRP**
Aging Equipment Replacement	3 transformers at Kingsville TS are at end-of-life	Near-Term	**RIP**
Aging Equipment Replacement	2 autotransformers at Keith TS are at end-of-life	Near-Term	**RIP**

7. REGIONAL INFRASTRUCTURE PLANS

THIS SECTION PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE WINDSOR-ESSEX REGION.

7.1 Supply to Essex County Transmission Reinforcement (SECTR) Project

7.1.1 Description

The SECTR project as presented in the IRRP is an integrated solution to address both the J3E-J4E subsystem restoration need and the Kingsville – Leamington capacity need. As illustrated in Figure 7-1 the project consists of the installation of a new 230 kV supplied transformer station near Leamington connected to the existing C21J/C22J circuits via a new 13 km double-circuit 230 kV connection line on a new right-of-way.

The total cost of this project is $96.7M made up of:

(a) Build 230/27.6 – 27.6 kV 75/100/125 MVA Leamington TS with six LV breaker positions, plus other required switchgear: $32.1M
(b) Build a 13 km 2-circuit 230 kV line on a new right-of-way tapping into existing 230 kV circuits C21J/C22J plus Optical Ground Wire: $45.3M.
(c) Carry out distribution work for Leamington TS: $19.3M. Other additional distribution work includes two additional feeder positions at Leamington TS, and protection upgrades for in-service Kingsville DG transferred to Leamington TS.

With the establishment of Leamington TS, load will be transferred from Kingsville TS to the new station, such that the Kingsville TS load will be reduced to about 50 MW. As discussed in the IRRP report, this presents an opportunity to downsize the station from four transformers to two transformers, and would result in a combined supply capability in the Kingsville-Leamington area of 210 MW.

Figure 7-2 is a preliminary plan for the transfer of Kingsville TS feeders to Leamington TS. Feeders which are shown in blue will be completely transferred to Leamington TS, and the ones shown in green will be partially transferred to Leamington TS.

7.1.2 Recommended Plan and Current Status

Hydro One filed an application on January 22, 2014 with the OEB under Section 92 of the OEB Act for an order granting leave to construct approximately 13 km of new 230 kV transmission lines on steel lattice towers on a new right of way in the Windsor-Essex area and the installation of optic ground wire for system telecommunication purposes on existing C21J/C23Z towers near Leamington Junction and on new 230 kV towers. The application included a request for OEB approval of the methodology for allocating project cost to Hydro One Distribution, embedded LDCs and Sub-Transmission class customers.

On February 12, 2015, Hydro One filed an updated application that included the new 230/27.6 kV Leamington Transformer Station (Leamington TS). The OEB decided that the proceeding would be addressed in two phases. Phase 1 would only deal with the leave to construct application and Phase 2 of the proceeding would deal with cost allocation. Phase 1 of the SECTR S.92 proceeding has concluded and the "Leave to Construct" approval was granted by the OEB on July 16, 2015. The expected in-service date for the SECTR Project is June 2018. Phase 2 of the proceeding is continuing via an OEB policy review rather than the originally planned adjudicative process.

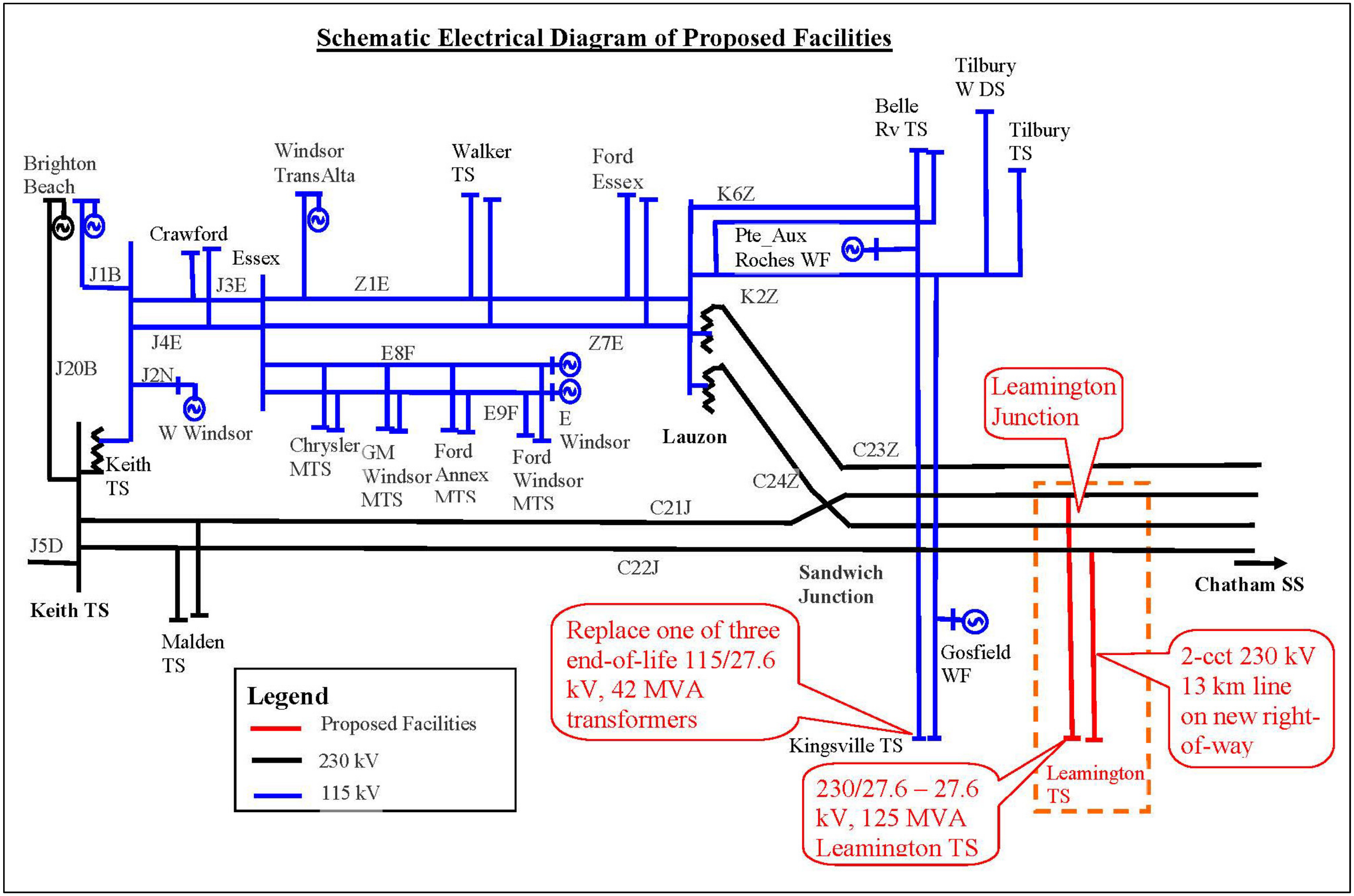

Figure 7-1 Schematic Electrical Diagram of the Proposed Facilities

Figure 7-2 Preliminary Distribution Feeder Plans for SECTR Project

7.2 Keith TS End-of-Life Auto-Transformer Replacement

7.2.1 Description

Keith TS is equipped with 2-230/115 kV 115 MVA autotransformers. These autotransformers are 1950's vintage and near end-of-life and require replacement.

7.2.2 Recommended Plan and Current Status

Due to SECTR project additional capacity will not be required and the end-of-life autotransformers at Keith TS will be replaced with equivalent like-for-like 125 MVA units. The expected in-service date is 2020. There are no cost implications for the LDCs.

7.3 Kingsville TS End-of-Life Transformer Replacement

7.3.1 Description

Kingsville TS is equipped with 4-115/27.6 kV 25/33/42 MVA transformers. One of these transformers was recently replaced, but the other three are 1950's vintage and will require replacement in the near future.

Due to SECTR project and the associated reduction in load at Kingsville TS, the station may be downsized and reconfigured as a two-transformer station. Hydro One Distribution is further reassessing to justify retaining the four-transformer arrangement if they receive additional request for connections at Kingsville area.

7.3.2 Recommended Plan

Hydro One Distribution to complete their connection capacity assessment as part of distribution system planning before Q3 2016 so that replacement and reconfiguration plan can be finalized by Hydro One in a timely manner.

7.4 Gordie Howe International Bridge (GHIB)

7.4.1 Description

The Gordie Howe International Bridge (GHIB) is a construction project under a bi-lateral agreement between the federal governments of Canada and the USA, and the governments of Ontario and Michigan, to construct a new border crossing between Windsor and Detroit. It will comprise a 12 km westerly extension of Hwy 401 to a site near Keith Transformer Station, where a new customs plaza and a new bridge over the Detroit River will be constructed. The highway will be extended by the Ministry of Transportation of Ontario (MTO), while the customs plaza and the bridge will be constructed by Transport Canada.

The GHIB project is multi-faceted in its impacts on Hydro One facilities and operations at Keith TS including: transmission lines, fiber lines and feeders relocation; insulation contamination due to salt spray effects from new bridge; relocation of access routes; possible security issues for staff accessing and working at the station; impacts on existing utilities (water/sewer/gas). In addition, the GHIB project will reduce the footprint of the station and encumber egress from the station. Consequently, this project will impact future expansion work at the station and possibly limit the extent to which the station can be developed relative to its ultimate plan development over the long term.

7.4.2 Recommended Plan and Current Status

In order to mitigate these impacts, as illustrated in Figure 7-3 below, additional real estate is required for future expansion to the north of McKee Rd. The existing transmission lines and feeders will also need to egress the station via underground cables so as not to interfere with the bridge operations.

The cost of this project will be fully recovered from the Windsor Detroit Bridge Authority (WDBA). A Transmission Assets Modification Agreement (TAMA) with the WDBA is expected to be finalized by early January 2016. Approvals for executing the project are expected by March 2016 for a planned in-service date by the end of 2018.

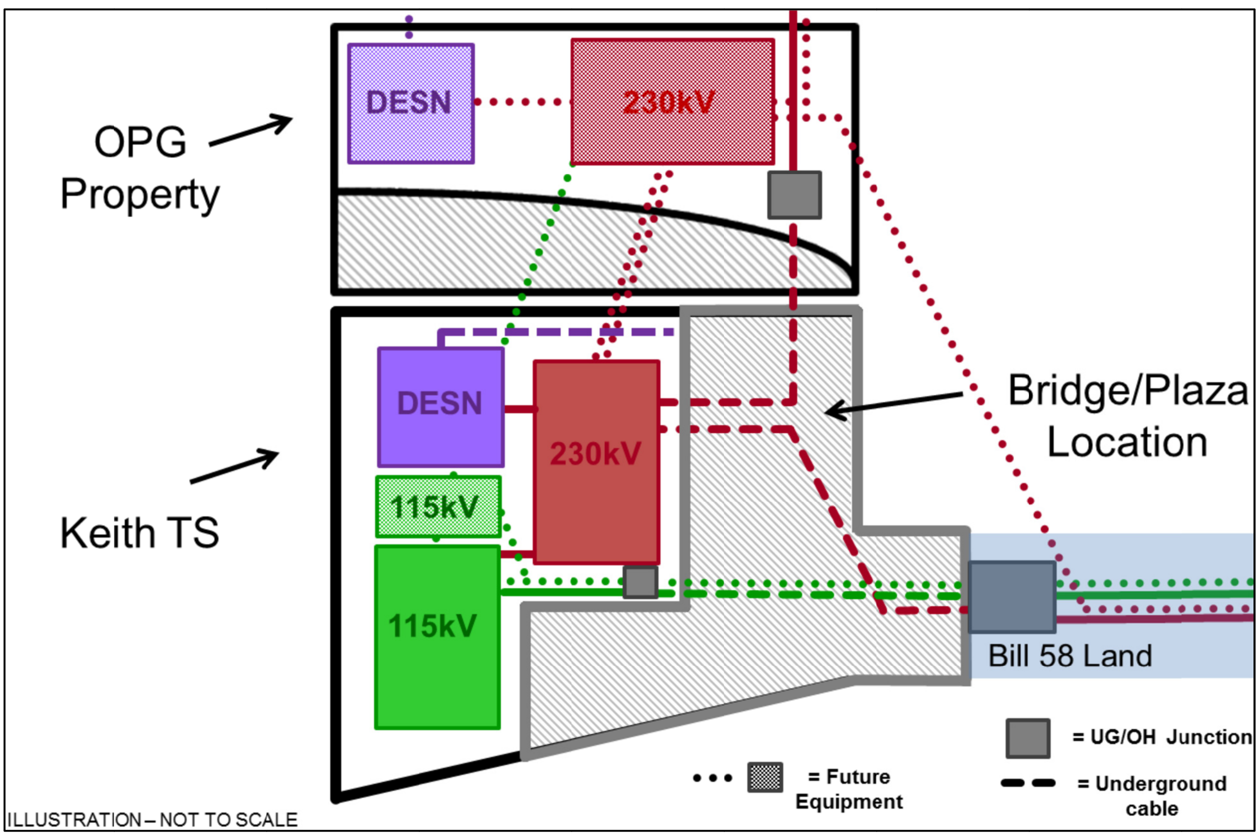

Figure 7-3 Gordie Howe International Bridge (GHIB) Project

8. OTHER PROJECTS

There are other wires projects that are currently under development and pending decision in the Windsor-Essex Region. These projects are local in nature and being planned and developed by Hydro One and relevant LDC as discussed below.

8.1 Malden TS Additional Feeder Positions

8.1.1 Description

Due to the load increase that's expected from the planned Detroit River International Crossing work and local highway construction, Essex Power has identified a need for two additional 28 kV feeder positions to be constructed at Malden TS.

The Malden transformer station is currently equipped with two 75/125 MVA transformers, 12 feeder positions and two capacitor banks and this plan involves expanding the station to 14 feeders. The two transformers at Malden TS were recently replaced, and there is additional capacity available at the station to meet the load requirement of the customer.

Based on a preliminary estimate the following will be the cost for the different layouts:

- Installation of two 28kV feeder breaker positions with feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $1.1M
- Installation of one 28kV feeder breaker position with no feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $875k
- Installation of one 28kV feeder breaker position with a break before make connection to alternate bus with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $925k

8.1.2 Recommended Plan and/or Current Status

The above options have been provided to Essex Powerlines Corp. Hydro One is awaiting its decision on the preferred option expected to be made in 2016.

8.2 Tilbury TS Transformer End-of-Life Replacement

8.2.1 Description

Tilbury West HVDS and Tilbury TS are both supplied from 115 kV circuit K2Z and are adjacent to each other. The two stations supply the Town of Tilbury and surrounding area. Tilbury West HVDS consists of 2 x 15/20/25 MVA, 115/27.6 kV transformers of 1980's vintage with two feeder positions; and Tilbury TS consists of 1 x 6/8 MVA 115/27.6 kV transformer of 1950's vintage with one feeder position. The

2014 peak load at Tilbury TS was 1.0 MW, and 16 MW at Tilbury West HVDS. The future load levels over the next 10 years at these stations are not expected to grow significantly.

Tilbury TS is near its end-of-life, and a decision to replace or retire should be made by 2017. Following three options are under consideration for Tilbury TS:

(1) Transfer Tilbury TS load (M1 feeder) to Tilbury West DS and decommission Tilbury TS at a cost of about $1.7M. This option is feasible as there is sufficient capacity at Tilbury West HVDS to accommodate both the Tilbury West HVDS forecast load and the Tilbury TS forecast load into the long term. Further, Tilbury West HVDS has sufficient capacity to accommodate its existing DG connections plus the existing 5 MW solar DG currently connected to Tilbury TS.

(2) Refurbish Tilbury TS at a cost of about $5M. This option would retain the supply capacity level and supply diversity that currently exists.

(3) Build a new DESN station at Tilbury TS with dual 115kV circuit supply from the K2Z and K6Z for an expected cost of about $20M. This would include building the 115kV line out from Tilbury Junction to the TS and a complete new station.

8.2.2 Recommended Plan and Current Status

Option 1 is the least cost alternative. It is recommended that Hydro One will have further discussions with the LDCs regarding these options and associated costs. These discussions are expected in 2016, and a decision is expected to be made by no later than 2017. Project construction is planned to commence in 2018 for an expected in-service in 2019. Depending on the option selected, costs may have to be recovered from the LDCs consistent with the TSC.

8.3 Keith TS T1 Transformer End-of-Life Replacement

8.3.1 Description

Keith TS transformer T1 (25/33/42 MVA 115/27.6 kV) is of 1950's vintage and it is approaching end-of-life. EnWin is the only LDC supplied from this Keith T1 and exclusively serves a single customer Nemak. The peak load was 8 MW in 2014. The load growth is expected to remain at this level in the long-term.

There is sufficient capacity at the Keith DESN station to accommodate both the forecast at Keith DESN load plus the forecast Keith TS T1 load over the next 10 years.

Following three possible options are considered to address the end-of life issue for Keith TS T1:

(1) Replace Keith TS T1.

(2) Transfer Keith TS T1 load to Keith T22/T23 DESN station.

(3) Resupply Nemak from another EnWin feeder connected to Keith T22/T23 DESN.

8.3.2 Recommended Plan and Current Status

It is recommended to develop cost estimates for each of the option. Following that Hydro One will initiate discussions with EnWin to review the options and decide on a preferred option.

Cost estimates are expected in Q1 of 2016 and selection of a preferred option is expected before the end of 2016. Discussions will then ensue with Hydro One and EnWin regarding planned construction dates.

9. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE WINDSOR-ESSEX REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report provides a single consolidated source of information for infrastructure plans in the Windsor-Essex Region. It develops and outlines a plan for investments in transmission and/or distribution facilities to meet the electricity needs within the region. The RIP report was developed in collaboration of a Technical Working Group consisting of representation from the LDCs in the region, the IESO, and led by Hydro One consistent with the requirements set out in the TSC, DSC and the PPWG report.

This report highlights several near-term needs in the region for which implementation plans have already been developed and are planned for completion in the next five years. Table 9-1 provides a status of these projects along with their cost and timelines. Projects requiring further planning on scoping and pending decisions on the preferred alternative are provided in Table 9-2. Over the next five years, the total transmission and distribution investments associated with these projects is approximately $215M - $225M.

Table 9-1 Project Under Development

Project/Plan	Cost	I/S	Performed by
Supply to Essex County Transmission Reinforcement “SECTR TX”	$77.4 Million	March 2018	Hydro One
Supply to Essex County Transmission Reinforcement “SECTR DX”	$19.3 Million	March 2018 (first stage)	Hydro One Distribution
Replacement of Keith end-of-life autotransformers	$45 Million	2020	Hydro One
Replacement of Kingsville end-of-life transformers	$12 Million	2018	Hydro One
230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	$63 Million	October 2018	Hydro One
Transformer replacement and station refurbishment at Crawford TS	$8.46 Million	December 2016	Hydro One

Table 9-2 Project Pending Decision

Project/Plan	Cost	I/S	Performed by
Additional feeder position at Malden TS	TBD	TBD	Hydro One
Replacement of Tilbury end-of-life transformer	TBD	2019	Hydro One
Keith TS end-of-life T1 Transformer	TBD	TBD	Hydro One

There are no long-term needs in this region that requires plans to be developed at this time. As with any region, the Windsor-Essex Region is monitored as part of Hydro One and LDC operations. Should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

10. REFERENCES

[1] Independent Electricity System Operator. "Windsor-Essex Region Integrated Regional Resource Plan". April 28, 2015.
http://www.ieso.ca/Documents/Regional-Planning/Windsor_Essex/2015-Windsor-Essex-IRRP-Report.pdf

APPENDIX A. GROSS FORECAST BY SUBSYSTEM & STATION

J3E/J4E Sub-System Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Kingsville TS	158	133	137	141	145	146	147	148	149	150	151	152	153	155	156	157	158	159	160	161	162
Belle River TS	59	46	46	47	48	49	50	51	52	53	53	54	55	56	57	58	59	60	61	62	63
Tilbury West DS	34	17	17	17	17	18	18	18	18	18	19	19	19	19	19	19	19	19	19	20	20
Tilbury TS	10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lauzon TS	225	191	193	195	197	199	201	203	204	206	208	209	211	213	215	217	219	221	223	224	226
Walker TS #1	99	71	79	76	77	77	78	78	79	79	80	80	81	81	82	82	83	83	84	84	85
Walker TS #2	99	95	111	92	92	93	93	94	94	95	96	96	97	97	98	99	99	100	100	101	102
Essex TS	116	55	63	73	73	74	74	75	75	76	76	77	77	78	78	78	79	79	80	80	81
Crawford TS	90	83	84	84	85	85	86	86	87	87	88	88	89	89	90	90	91	91	92	93	93
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**807**	**816**	**824**	**830**	**836**	**843**	**849**	**854**	**860**	**866**	**872**	**878**	**884**	**891**	**897**	**903**	**909**	**916**	**922**

Additional Stations in the Windsor-Essex Region Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	67	67	67	67	67	67	68	68	68	68	68	68	68	68	68	69	69	69	69
Malden TS	200	117	118	119	120	120	121	122	124	124	125	126	127	127	128	129	130	131	131	132	133
Windsor Essex Total	**N/A**	**962**	**1000**	**1009**	**1019**	**1026**	**1033**	**1041**	**1048**	**1055**	**1061**	**1068**	**1074**	**1082**	**1089**	**1096**	**1104**	**1111**	**1118**	**1125**	**1133**

Kingsville-Leamington Sub-system Gross Demand (weather normal)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Total	**N/A**	**155**	**160**	**165**	**169**	**172**	**174**	**177**	**178**	**181**	**183**	**186**	**188**	**191**	**193**	**196**	**199**	**201**	**204**	**206**	**209**

APPENDIX B. CONSERVATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		*Forecast*																			
Kingsville TS	158	1	2	3	3	4	6	9	10	11	12	14	15	16	18	20	21	22	24	25	26
Belle River TS	59	0	1	1	1	1	2	3	3	3	4	4	5	5	5	6	6	7	7	8	8
Tilbury West DS	34	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3
Tilbury TS	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lauzon TS	225	1	3	4	4	5	8	11	12	13	14	17	18	19	21	23	24	26	28	29	30
Walker TS #1	99	1	1	2	2	2	4	5	5	6	6	7	8	8	9	10	11	11	12	13	13
Walker TS #2	99	1	1	2	2	3	4	6	6	7	8	9	10	10	11	13	13	14	15	16	16
Essex TS	116	0	1	1	1	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	9
Crawford TS	90	1	1	1	2	2	3	4	4	5	5	6	7	7	8	9	9	10	10	11	11
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**N/A**	**5**	**10**	**14**	**16**	**20**	**31**	**41**	**45**	**50**	**55**	**64**	**69**	**75**	**81**	**89**	**94**	**100**	**107**	**114**	**115**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		*Forecast*																			
Keith TS T1	54	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Keith TS T22/T23	114	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Malden TS	200	1	2	2	3	3	5	7	7	8	9	11	11	12	14	15	16	17	18	19	19
Windsor Essex Total	**N/A**	**7**	**12**	**18**	**20**	**26**	**40**	**53**	**58**	**65**	**72**	**83**	**89**	**97**	**105**	**116**	**122**	**130**	**139**	**148**	**149**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		*Forecast*																			
Total	**N/A**	**1**	**2**	**3**	**3**	**4**	**6**	**9**	**10**	**11**	**12**	**14**	**15**	**16**	**18**	**20**	**21**	**22**	**24**	**25**	**26**

APPENDIX C. DISTRIBUTED GENERATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation		Forecast																			
Kingsville TS	158	15	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Belle River TS	59	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Tilbury West DS	34	2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tilbury TS	10	2	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Lauzon TS	225	8	16	18	19	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Walker TS #1	99	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Walker TS #2	99	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Essex TS	116	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Crawford TS	90	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**N/A**	**35**	**59**	**64**	**66**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation		Forecast																			
Keith TS T1	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keith TS T22/T23	114	21	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Malden TS	200	9	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Windsor Essex Total	**N/A**	**65**	**63**	**69**	**71**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation		Forecast																			
Total	**N/A**	**15**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**

APPENDIX D. REFERENCE PLANNING FORECAST BY SUBSYSTEM & STATION

J3E/J4E Sub-System Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Kingsville TS	158	133	114	117	121	121	120	118	118	118	118	117	117	118	117	116	116	116	115	115	115
Belle River TS	59	46	43	44	44	45	45	45	46	47	46	47	47	48	49	49	50	50	51	51	52
Tilbury West DS	34	17	7	7	7	8	7	7	7	7	8	7	7	7	7	7	7	7	6	7	7
Tilbury TS	10	1	-6	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7
Lauzon TS	225	191	174	173	174	174	173	172	172	173	174	172	173	174	174	174	175	175	175	175	176
Walker TS #1	99	71	76	72	73	73	72	71	72	71	72	71	71	71	71	70	70	70	70	69	70
Walker TS #2	99	95	109	89	89	89	88	87	87	87	87	86	86	86	86	85	85	85	84	84	85
Essex TS	116	55	62	71	71	71	70	71	70	71	70	71	70	71	70	70	70	70	70	70	71
Crawford TS	90	83	82	82	81	81	81	80	81	80	81	80	80	80	80	79	80	79	80	80	80
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**737**	**738**	**742**	**743**	**737**	**733**	**736**	**736**	**737**	**734**	**733**	**737**	**735**	**733**	**735**	**735**	**733**	**734**	**738**

Additional Stations in the Windsor-Essex Region Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	64	64	64	64	63	62	63	63	63	62	62	61	61	60	60	60	60	59	59
Malden TS	200	117	115	114	114	114	113	112	114	113	113	112	113	112	111	111	111	111	110	110	111
Windsor Essex Total	**N/A**	**962**	**924**	**923**	**928**	**930**	**922**	**916**	**920**	**921**	**921**	**916**	**915**	**919**	**916**	**912**	**915**	**914**	**912**	**911**	**917**

Kingsville-Leamington Sub-system Gross Demand (weather normal)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Total	**N/A**	**155**	**147**	**151**	**155**	**156**	**157**	**157**	**158**	**159**	**160**	**161**	**162**	**164**	**165**	**166**	**167**	**169**	**169**	**171**	**173**

APPENDIX E. LIST OF ACRONYMS

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

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

NEEDS ASSESSMENT REPORT

Region: Peterborough to Kingston

Revision: Final
Date: February 10, 2015

Prepared by: Peterborough to Kingston Region Study Team

Peterborough to Kingston Region Study Team	
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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston 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	Peterborough to Kingston Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	December 12, 2014	**END DATE**	Feb 10, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Peterborough to Kingston 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 (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 Peterborough to Kingston 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. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 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 study 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 Peterborough to Kingston Region. 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. See Section 4 for further details.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region 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 (Dobbin TS and Cataraqui TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- 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.
- Under high Transfer East of Cherrywood and low water conditions in the east, P15C may be loaded near its continuous rating under pre-contingency conditions. This issue will be further assessed by the IESO as part of bulk system planning.

C. 115kV Transmission Lines

- With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S may reach its LTE ratings in the near term based on the gross load forecast. The net load in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.
- The remaining 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.
- With the loss of 230 kV circuits P15C and C27P and expected load additional loading in Renfrew area in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue will be further assessed by the IESO as part of bulk system planning.

D. 230 kV and 115 kV Connection Facilities

- Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the net load forecast with planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted load over the study period. It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region. Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum 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, the load interrupted by configuration may exceed 150 MW based on the gross coincident load forecast. However, based on the net coincident load forecast, the load interrupted by configuration does not exceed 150 MW. No action is required at this time.

Aging Infrastructure / Replacement Plan

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

7. RECOMMENDATIONS

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

- "localized" wires only solutions be developed in the near-term to adequately and efficiently address the needs associated with transformation capacity relief for Gardiner TS T1/T2 DESN1 as indicated above through planning between Hydro One Networks Inc. and the impacted distributors. See Section 7 for further details, and
- IESO to assess loading constraints on circuit Q6S for the loss of two elements, and P15C under high transfers as part of their bulk system planning

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Peterborough to Kingston Region ("Region") over the next ten years. 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 Peterborough to Kingston Region 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 Peterborough to Kingston Region 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 Peterborough to Kingston Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
3.	Independent Electricity System Operator ("IESO")
4.	Kingston Hydro Corporation ("Kingston Hydro")
5.	Peterborough Distribution Inc. ("Peterborough Distribution")
6.	Veridian Connections Inc. ("Veridian")
7.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the Peterborough to Kingston Region 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 Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the Peterborough to Kingston Region 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 Peterborough to Kingston Region Description and Connection Configuration

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The boundaries of the Peterborough to Kingston Region are shown below in Figure 1.

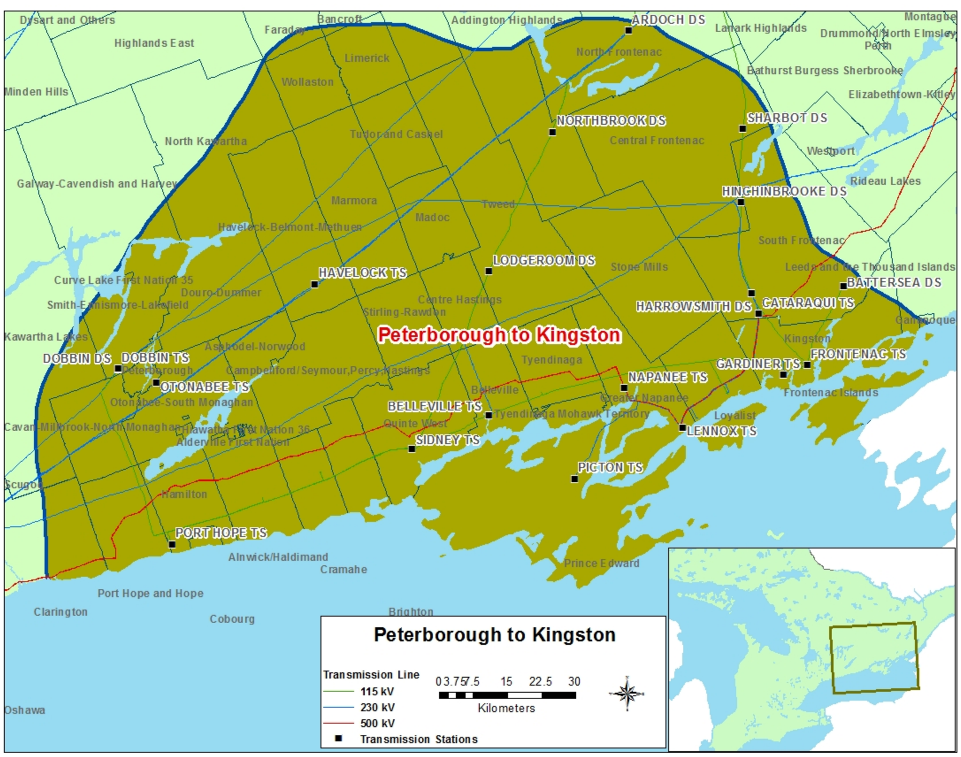

Figure 1: Peterborough to Kingston Region Map

Electrical supply to the Peterborough to Kingston Region is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Lennox Transformer Station (TS) and 230/115 kV autotransformers at Cataraqui TS and Dobbin TS. There are ten Hydro One step-down TS's, eight high voltage distribution stations (HVDS), and five other direct transmission connected load customers in the Region. The distribution system consists of voltage levels 44 kV, 27.6 kV, 12.5 kV, 8.32kV, and 4.16kV. The main generation facility in the Region is the 2000 MW Lennox Generation Station (GS) connected to Lennox TS.

The existing facilities in the Region 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:

- Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.

- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.

- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight HVDS that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS.

- Five Customer Transformer Stations (CTS) are supplied in the Region: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Belleville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.

- There are 3 existing Transmission connected generating stations in the Region as follows:
    - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
    - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
    - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS

- A 910 MW gas-fired plant (Napanee GS) is expected to connect to Lennox TS at the 500kV level in 2018.

- Up to 535 MW of additional transmission connected renewable generation could be in service in the Region by the year 2023.

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

Table 2: Transmission Lines in Peterborough to Kingston Region

Voltage	Circuit Designations	Location
230 kV	X1H, X2H, X3H, X4H	Hinchinbrooke SS to Lennox TS
	X21, X22	Picton TS to Lennox TS
	H23B	Belleville TS to Hinchinbrooke SS
	H27H	Hinchinbrooke SS to Havelock TS
	X1P	Dobbin TS to Chenaux TS
	C27P	Dobbin TS to Chat Falls GS
	H24C, H26C	Cherrywood TS to Havelock TS
	C28C	Cherrywood TS to Chat Falls GS
	P15C	Cherrywood TS to Dobbin TS
	B23C	Cherrywood TS to Belleville TS
115 kV	P3S, P4S	Dobbin TS to Sidney TS
	Q6S	Cataraqui TS to Sidney TS
	B1S	Barrett Chute TS to Sidney TS
	Q3K	Cataraqui TS to Frontenac TS
	B5QK	Cataraqui TS to Frontenac TS to Barrett Chute TS

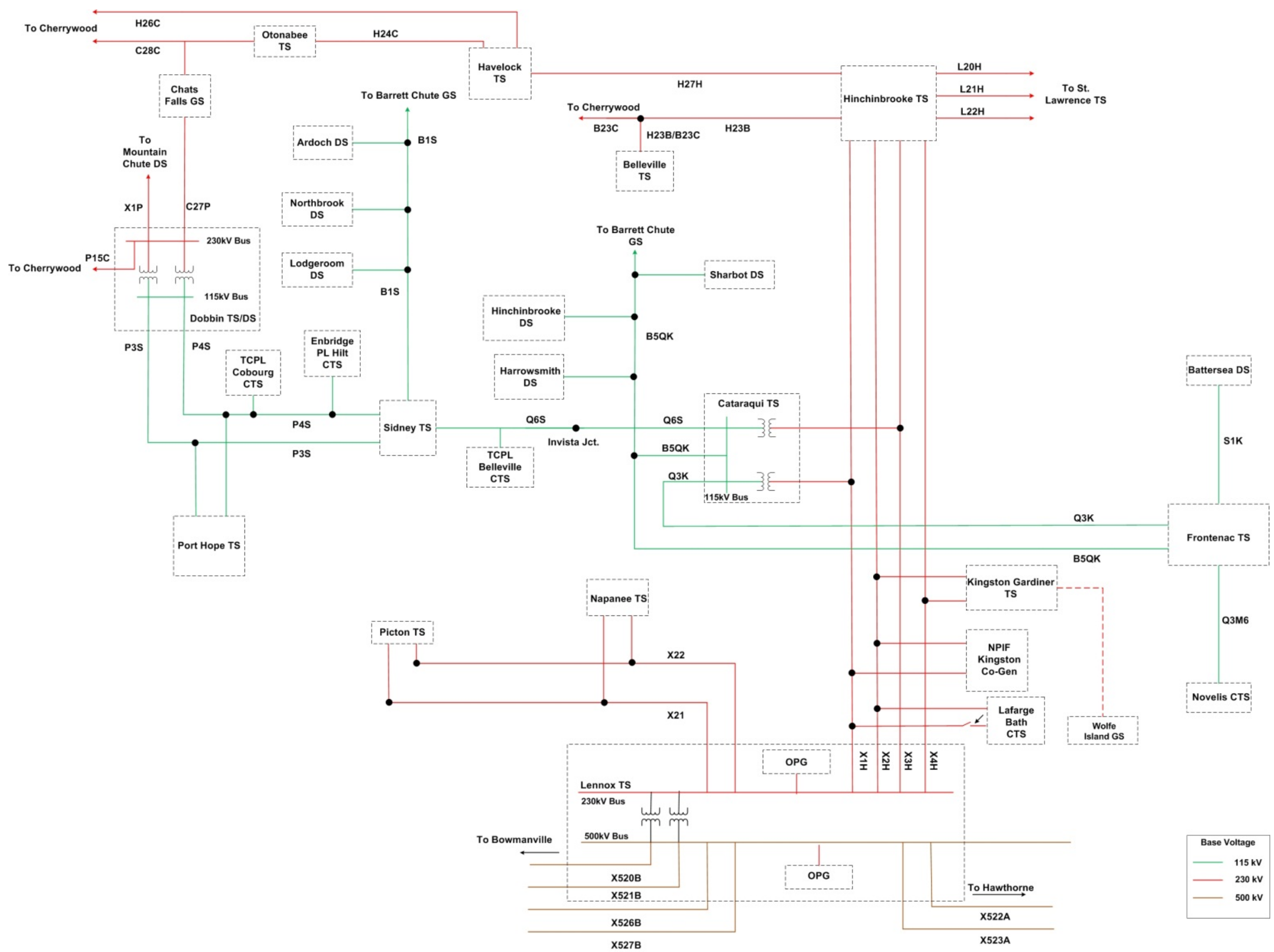

Figure 2: Single Line Diagram – Peterborough to Kingston Region

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

As per the data provided by the study team, the gross load in the Peterborough to Kingston Region is expected to grow at an average rate of approximately 0.4% annually from 2014-2023.

4.2 Net Load Forecast

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. The net load is expected to decrease at an average rate of approximately 0.6% annually from 2014-2023.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region consists of both winter and summer peaking stations. Therefore, this assessment is based on both winter and summer peak loads, as appropriate.

2. Forecast loads are provided by the Region's LDCs. LaFarge Canada had provided a load forecast for LaFarge Canada CTS. Load data was not received by the other industrial customers in the region (Enbridge Pipeline Inc, TransCanada Pipeline Ltd.). For these stations, the load was assumed to be consistent with historical loads.

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

4. The 2013 summer/winter peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

5. Accounting for (2), (3), (4) 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 gross and 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.

6. Review impact of any on-going and/or planned development projects in the Region during the study period.

7. 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.

8. 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 or winter 10-Day Limited Time Rating (LTR), as appropriate.

9. 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.

10. 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 Peterborough to Kingston Region.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Dobbin TS and Cataraqui 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 circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

Under high Transfer East of Cherrywood and low water conditions in Eastern Ontario, the 230 kV circuit P15C may be loaded near its continuous rating under pre-contingency conditions. This issue should be further assessed by the IESO as part of bulk system planning.

6.1.3 115kV Transmission Lines

With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S from Invista Jct to Sidney TS may reach its LTE rating in the near term based on the gross load forecast. The net load forecast in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.

With the loss of 230 kV circuits P15C and C27P and expected additional loading in the Renfrew region in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue should be further assessed by the IESO as part of bulk system planning.

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

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 and HVDSs in the Region using either the summer or winter station peak load forecasts as appropriate that were provided by the study team. The results are as follows:

Gardiner TS

Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted demand over the study period.

It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

All the other TSs and HVDSs in the Region are forecasted to remain within their normal supply capacity during the study period. Therefore, no action is required at this time and the capacity needs will be reviewed in the next planning cycle.

6.2 System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region.

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum 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 circuits X2H and X4H, the load interrupted by configuration at Gardiner TS may exceed 150 MW based on the gross coincident load forecast. 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.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables.

During the study period:

- Replacement (like-for-like) of both transformers (T1 and T2) at Gardiner TS DESN1 is scheduled in 2020. The replacement plan does not affect the results of this NA study.

- Replacement of two autotransformers, T2 and T5 (78 MVA and 115 MVA respectively), at Dobbin TS with a single 150/250 MVA autotransformer is scheduled in 2019. The third autotransformer (T1) will remain the same. The replacement plan does not affect the results of this NA study.

- There are no significant lines sustainment plans that will affect the results of this NA study.

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that no further coordinated regional planning is required.

Rather the study team recommends the following to address the identified needs:

a) Hydro One transmission will lead the assessment and develop a local plan ("Gardiner TS Load Balancing") with the relevant LDCs to balance load between the two DESNs at Gardiner TS; and,
b) IESO to assess and develop a plan for the contingencies associated with circuit Q6S for the loss of two elements and loading constraints on circuit P15C under high transfers within the context of a bulk planning study for the area.

8 NEXT STEPS

Hydro One Transmission and impacted LDCs will address the recommendation in Section 7a and develop a local plan.

IESO to initiate a bulk planning study for the area.

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
IESO	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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December 7, 2015

Bing Young
Director, System Planning
Hydro One Networks, Inc.
483 Bay Street
Toronto, ON M5G 2P5

Dear Bing:

Re: Initiating a Near-term Transmission Project identified through the Barrie/Innisfil Integrated Regional Resource Planning ("IRRP") process

The purpose of this letter is to:

- Hand off a near-term transmission project to Hydro One that is required to address urgent needs to replace infrastructure nearing its end of life and provide supply capacity in the Barrie/Innisfil sub-region; and
- Request that Hydro One begin development of a project to replace the existing Barrie transformer station ("Barrie TS") and the E3/4B transmission line with new 230 kV infrastructure.

Since a wires option has been determined to be the only feasible means to address these urgent needs, the hand off of this transmission project to Hydro One is consistent with the regional planning process endorsed by the Ontario Energy Board ("OEB") as part of its Renewed Regulatory Framework for Electricity.

The Barrie/Innisfil Working Group ("the Working Group"), consisting of staff from the IESO, Hydro One, PowerStream and InnPower, is conducting an IRRP process for the Barrie/Innisfil sub-region. The Terms of Reference for the Barrie/Innisfil IRRP established a phased planning process to ensure that near-term needs could be met in a timely fashion. The Working Group has completed the first phase of the IRRP, including reviewing options to address near-term needs with consideration of future needs, meeting with municipalities in the sub-region, and meeting with First Nation communities in the broader South Georgian Bay/Muskoka region. Due to the nature and the timing of the needs, which include replacing existing infrastructure that is approaching its end of life, and providing additional capacity to supply growth in the City of Barrie and Town of Innisfil in the near and medium term, the Working Group has concluded that non-wires alternatives are not viable options and recommends development of this near-term transmission project. The objectives and scope of this project are provided in Attachment 1.

At this time, the Working Group recommends that Hydro One proceed immediately with development of the transmission project, including pursuing the required environmental and regulatory approvals. The Working Group will continue to develop the medium- and long-term plan for the Barrie/Innisfil sub-region in parallel, and will benefit from updated information from Hydro One through the development of this project.

To facilitate development of this project, the IESO will provide Hydro One with the following information on request:

- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

We look forward to ongoing exchange of information, results and deliverables from the Barrie/Innisfil near-term transmission project as part of the Barrie/Innisfil Working Group activities, and to continuing to work with and provide support to Hydro One in the implementation of this project.

Yours truly,

Bob Chow
Director, Transmission Integration

Cc: Barrie/Innisfil IRRP Working Group Members:

PowerStream
Irv Klajman
Michael Swift
Riaz Shaikh

InnPower
Wade Morris
Ali Syed

Hydro One Distribution
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Richard Shannon
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Ajay Garg
Harneet Panesar

IESO
Michael Lyle
Nicole Hopper
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Julia McNally
Luisa da Rocha
Amanda Flude
Tabatha Bull
Mark Wilson
Leonard Kula
Ahmed Maria
Phillip Woo

Attachment 1 – Project Objectives and Scope

Project Objectives:

- To address the "end of life" of the Barrie transformer station ("Barrie TS") and the infrastructure that supplies it: the E3/4B transmission line; and the 230/115 kV autotransformers at the Essa transformer station ("Essa TS"). Various elements of this infrastructure range from 40 to 67 years old and have been identified for replacement as early as 2018 by Hydro One's sustainment program. These assets are indentified in Figure 1.
- To provide capacity to supply growth in the southern portion of the City of Barrie and in the Town of Innisfil. Currently, Barrie TS is the primary source of supply for this area. Based on current forecasts (net of conservation and distributed generation), this station will reach its capacity around 2017. Distribution system enhancements currently planned by PowerStream will enable this need to be deferred until around 2020, at which point additional supply capability will be required.

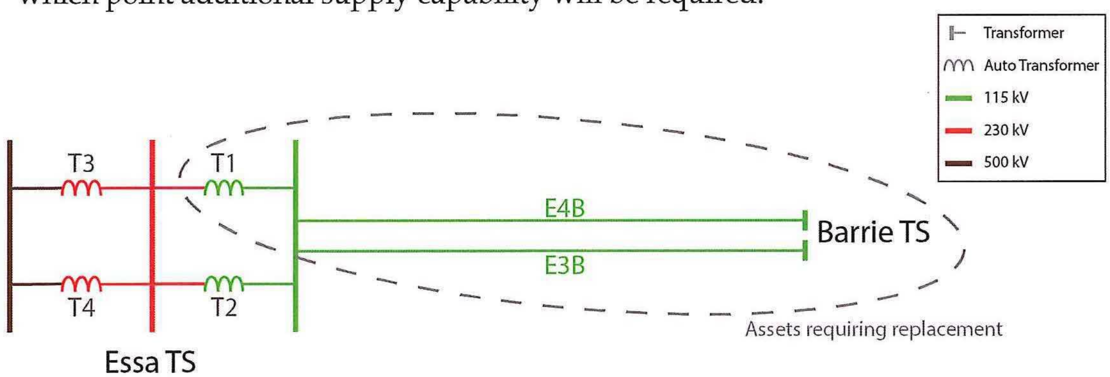

Figure 1 - Single line diagram detailing existing supply of Barrie TS and assets requiring replacement

Project Scope:

The Working Group has considered various alternatives for meeting the above objectives, including non-wires alternatives and various wires options:

- Non-wires solutions were determined to be infeasible by the Working Group on the basis that over 100 MW of existing customer load in southern Barrie and the Town of Innisfil that is currently supplied by Barrie TS would be left without electricity supply if the infrastructure is not replaced when it reaches end of life.
- An option to replace the existing 115 kV line, station and autotransformer with like-for-like equipment (i.e., maintaining its voltage at 115 kV) was also ruled out on the basis that it would not address the growth requirements in the area. Any additional capacity needed to supply growth would then require development of new, greenfield station site(s) and rights-of-way, which would be inconsistent with the 2014 Provincial Policy Statement.[1]

[1] Section 1.6.3 of the 2014 Provincial Policy Statement states that: "Before consideration is given to developing new *infrastructure* and *public service facilities*: a) the use of existing *infrastructure* and *public*

Based on the above considerations, the Working Group recommends that Hydro One proceed with a project consisting of:

- Rebuilding Barrie TS and the E3/4B transmission line and upgrading the voltage of these facilities from 115 kV to 230 kV;
- Upgrading the transformers at Barrie TS from 55/92 MVA units to 75/125 MVA units; and
- Retiring the two 230/115 kV auto-transformers at Essa TS (T1 and T2).

These measures address the near-term need to refurbish Barrie TS, allowing it to continue supplying the existing load in southern Barrie and the Town of Innisfil. At the same time, upgrading the station and line to 230 kV allows for the additional load growth forecast in this area to be supplied for the near and medium term using the existing station site and transmission right-of-way. Upgrading the transmission line to 230 kV also provides increased capability that allows for future development of the system. Additionally, savings are incurred from removing the 230/115 kV auto-transformers at Essa TS that are currently maintained solely to supply Barrie TS.

Due to the timing of the needs, and considering typical development timelines for transmission refurbishment/upgrade projects, Hydro One should work toward a targeted in-service date of 2020. It is the Working Group's understanding that a Class Environmental Assessment process will be required for this project, as well as Leave to Construct approval from the OEB for the line replacement portion of this project. The IESO will endeavor to provide support to Hydro One in these activities.

The Working Group will continue to review the medium- and long-term needs in the Barrie/Innisfil sub-region and will develop an IRRP addressing needs over a 20-year period for publication at the end of 2016.

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service facilities should be optimized; and b) opportunities for adaptive re-use should be considered, wherever feasible."

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NEEDS ASSESSMENT REPORT

Region: Sudbury Algoma

Date: March 12, 2015

Prepared by: Sudbury - Algoma Region Study Team

Sudbury to Algoma Region Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra
Independent Electricity System Operator	Phillip Woo Angelina Tan Kun Xiong
Greater Sudbury Hydro	Brian McMillan
Hydro One Networks Inc. (Distribution)	Richard Shannon

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Sudbury Algoma 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	Sudbury to Algoma (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 20, 2014	**END DATE**	March 20, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Sudbury to Algoma 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, 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 Sudbury Algoma 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. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Sudbury Algoma Region belongs to Group 2. The NA for this Region was triggered on October 20, 2014 and was completed on March 20, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 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 study of transmission system connection facilities capability, which covers station 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 Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Sudbury Algoma Region. 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.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region 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 Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Algoma TS, Martindale TS, Hanmer TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- 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. 115kV Transmission Lines

- The 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.
-

D. 230 kV and 115 kV Connection Facilities

- The 230k and 115kV connection facilities in this region are adequate over the study period.

E. Pre-contingency voltages at Manitoulin TS

- Under peak load conditions, pre-contingency voltages at Manitoulin TS 115kV bus can be below 113 kV.

System Reliability, Operation and Restoration Review

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum 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 one or two elements, the load interrupted by configuration does not exceed 150 MW or 250 MW. In addition,

- As identified by the IESO, under peak load conditions, the loss of two Martindale TS 230/115kV transformers may result in the overload of the third Martindale transformer.
- As identified by the IESO, With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC limits.

The above issues will be further assessed as part of bulk system planning outside of the regional planning process.

Aging Infrastructure / Replacement Plan

Replacement of the autotransformers at Martindale is currently in Hydro One's 5yr sustainment business plan. As part of this replacement, T21/T23 autotransformer replacement at Martindale TS may result in higher emergency ratings.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination is required and following needs identified in Section 6 be further assessed as part of Local Planning:

Manitoulin TS Voltage Regulation

- Low pre-contingency voltages at Manitoulin TS 115kV bus.

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1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Sudbury to Algoma Region ("Region") over the next ten years. 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 Sudbury to Algoma Region 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. If localized wires only solutions do not require further coordinated regional planning, 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 Sudbury to Algoma Region 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 Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Sudbury to Algoma Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Greater Sudbury Hydro Inc ("Sudbury Hydro")
4.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the Sudbury to Algoma Region 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 Sudbury to Algoma Region belongs to Group 2. The NA for this Region was triggered on October 20, 2014 and was completed on March 20, 2015

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the Sudbury to Algoma Region 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 capacity, 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 Sudbury to Algoma Region Description and Connection Configuration

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

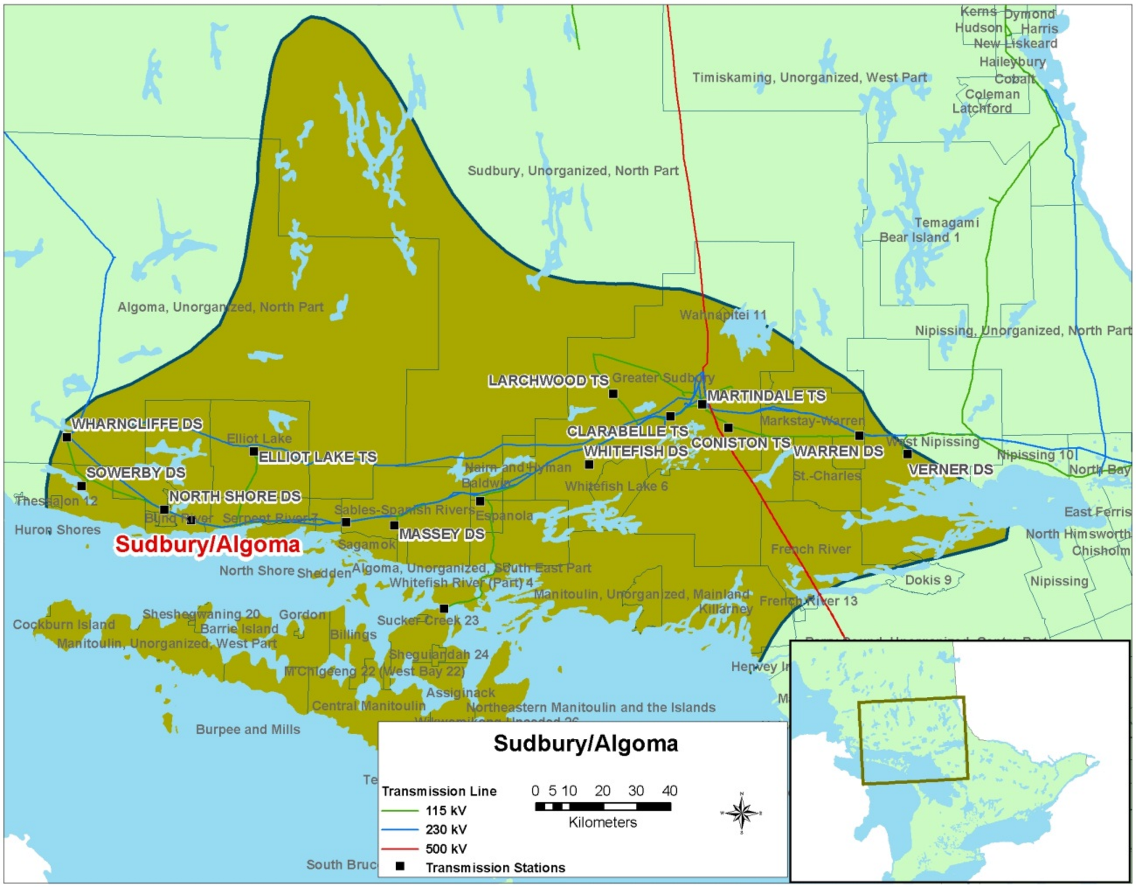

Figure 1: Sudbury to Algoma Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS (Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to Northwest Ontario through Mississagi TS. Table 2 below lists the major transmission circuits and Hydro One stations in the subject region.

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

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

Espanola Regional Hydro Distribution is a third LDC in this region embedded into the Hydro One Disribution system. Although invited to participate in the Study Team, the interests of this LDC was communicated through Hydro One Distribution.

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

115kV circuits	**230kV circuits**	**Hydro One Transformer Stations**
S6F,S5M	X74P, X27A	ALGOMA TS
S2B,B4B	A23P, A24P	MARTINDALE TS
T1B, B3E	X23N, S21N	HANMER TS
B4E, L1S	X25S, X26S	CONISTON TS
	S22A	CLARABELLE TS
		ELLIOT LAKE TS
		ESPANOLA TS
		LARCHWOOD TS
		MANITOULIN TS

Table 2: Transmission Lines and Stations in Sudbury to Algoma Region

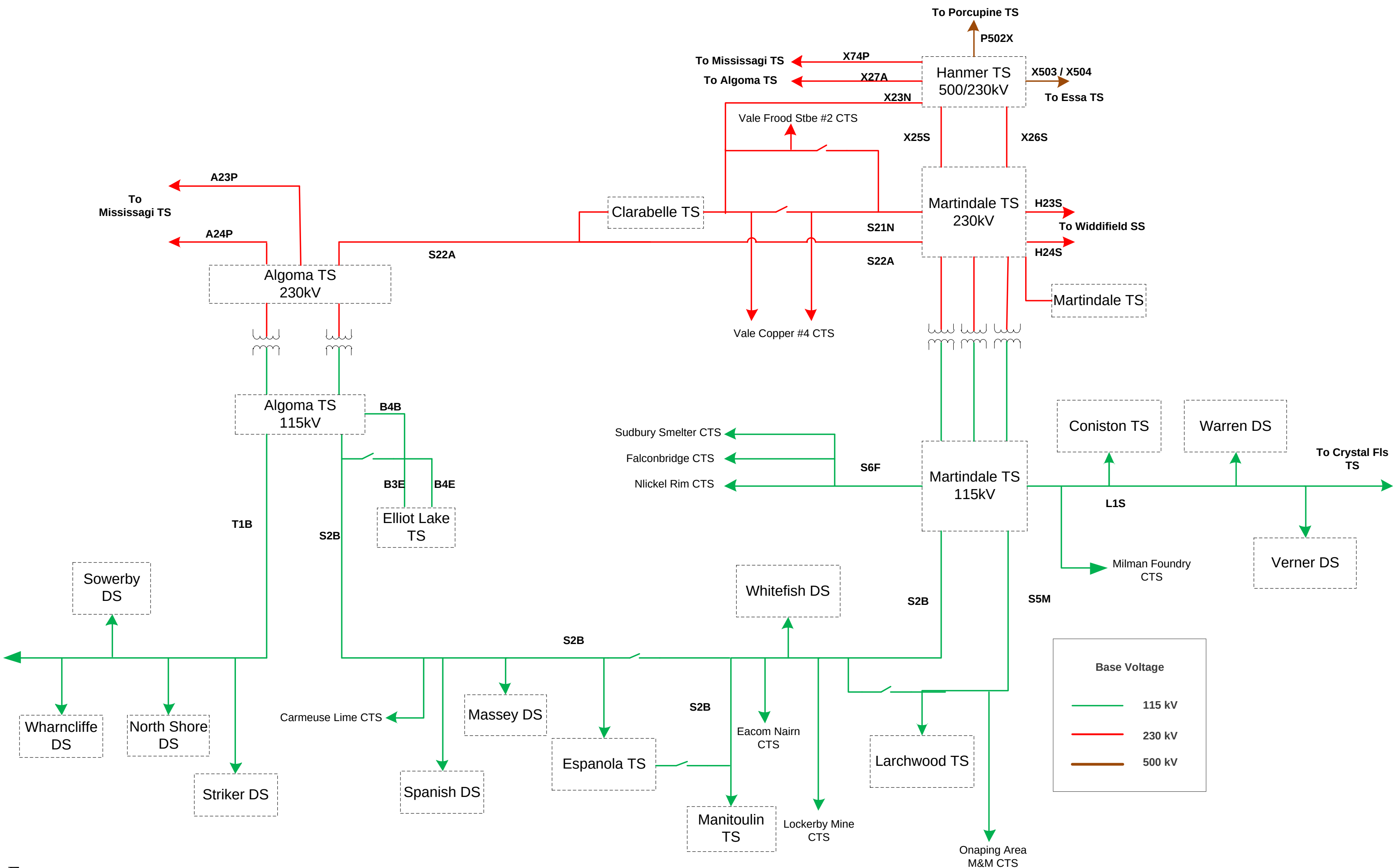

Figure 2: Single Line Diagram – Sudbury to Algoma Region

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 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.3% annually from 2014-2023.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. The net load is expected to decrease 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 Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region's LDCs (Greater Sudbury Hydro Inc, Hydro One Distribution).
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 winter peak load as a reference point.
5. The 2013 winter peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

6. Accounting for (2), (3), (4) 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 gross and net non-coincident peak load forecast was used to perform the analysis for Section 6.1.3 of this report.

   A gross and net region-coincident peak load forecast was used to perform the analysis for sections 6.1.1 and 6.1.2.

   Review impact of any on-going and/or planned development projects in the Region during the study period.
7. 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.
8. 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 or winter 10-Day Limited Time Rating (LTR), as appropriate.
9. 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.
10. 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 winter long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using winter loading with winter 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) 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 criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Sudbury to Algoma Region.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Algoma TS, Martindale TS, Hanmer 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 Transmission Lines & Ratings

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.

The 115 kV circuits supplying the Region are adequate over the study period.

6.1.3 230 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 station winter peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period (2014-2023).

6.1.4 Pre-contingency voltages at Manitoulin TS 115kV

Pre-contingency voltages at Manitoulin TS 115kV bus can be below the ORTAC criteria of 113 kV. This issue has been also identified by the IESO as part of their System Impact Assessments.

6.2 System Reliability, Operation and Restoration

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum 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 one or two elements, the load interrupted by configuration does not exceed 150 MW or 250 MW. Review of the power network in the area indicates that all loads in the Sudbury-Algoma area can be restored within the 8 hour requirement.

6.2.1 Post contingency voltage declines at Martindale TS

With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC limits. This issue has been presented in the IESO System Impact Assessment Victoria

Advanced Exploration Project (CAA 2013-512). In this assessment, voltage declines at the Martindale 230kV and 115 kV buses were found to be greater than the 10% limit.

6.2.2 Post Contingency Thermal Overload of Martindale Autotransformers

Under peak load conditions, the loss of two Martindale 230/115kV transformers may result in the overload of the third Martindale transformer. This issue has been presented in the IESO System Impact Assessment Process Gas (CAA 2012-488).

The double element contingency presented here occurs on the premise that all 115kV area loads would be supplied from one remaining autotransformer at Martindale TS. The worst case would be with Martindale T23 transformer remaining as it has the lowest STE (Short Term Emergency) rating.

Replacement of the autotransformers is listed in Hydro Ones 5yr sustainment business plan. T21/T23 autotransformers at Martindale TS may result in higher emergency ratings. In addition, loads connected to S2B (from Martindale) can also be transferred to S2B from Algoma, reducing Martindale 115kV load.

The above issues (6.2.1, 6.2.2) will be further assessed as part of bulk system planning outside of the regional planning process.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables.
During the study period:

- Replace T21/T23 230/115kV autotransformers at Martindale TS
- Build a new 230/44kV station at Hanmer TS to replace Coniston TS (115/22kV). As part of this project, Coniston loads will be converted from 22kV to 44kV
- Replace 115/44kV power transformers at Espanola TS (T1/T2) and Larchwood TS (T2)

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that no further coordinated regional planning is required. It is further recommended that following needs identified be best addressed by wires options thru local planning led by Hydro One:

Manitoulin TS - Pre-contingency voltages

- Low pre-contingency voltages at 115kV Manitoulin TS.

8 NEXT STEPS

Following the Needs Assessment process, the next regional planning steps, based on the evaluation conducted by this assessment is for Hydro One Transmission and impacted LDCs to carry out the local planning studies identified 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
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
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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NEEDS ASSESSMENT REPORT

Region: North and East of Sudbury

Date: April 15, 2016

Prepared by: North and East of Sudbury Region Working Group

North & East of Sudbury Working Group	
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Hydro One Networks Inc. (Distribution)	Richard Shannon Daniel Boutros
Northern Ontario Wires Inc	Dan Boucher
Hearst Power Ltd	D Sampson J Richard
North Bay Hydro Distribution Ltd	Matt Payne

Disclaimer

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 15, 2015	**END DATE**	April 15, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the North & East of Sudbury 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, 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 North & East of Sudbury 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. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The North & East of Sudbury Region belongs to Group 3, triggered on October 15, 2015 and completed on April 17, 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 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 2026. 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 study of transmission system connection facilities capability, which covers station 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

Working Group participants included representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One. 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.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2026). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required.

6. RESULTS - TRANSMISSION NEEDS

A. 500/230kV Autotransfomers
The 500/230kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/230kV unit.

B. 500/115kV Autotransfomers
The 500/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/115kV unit

C. 230/115 kV Autotransformers
The 230/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 230/115kV unit

D. Transmission Lines & Ratings
The 500kV, 230kV transmission lines are adequate over the study period.

Sections of the 115kV H9K circuit may experience thermal overloads during high generation scenarios. This is a bulk system issue and will be addressed jointly with the IESO outside of regional planning.

E. 230 kV and 115 kV Connection Facilities
The 230kV and 115kV connection facilities in this region are adequate over the study period.

F. Outage Condition resulting in P15T,P7G and T61S radially connected to Timmins TS
The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus

G. Ansonville T2 or D3K Outages
With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at the Kirkland Lake TS 115kV bus.

System Reliability, Operation and Restoration Review

Circuit reliability in the region is acceptable, and Hydro One will continue to monitor performance of supply stations and circuits to ensure customer delivery performance criteria are met.

Restoration requirements for the loss of one element can be met by Hydro One.
Restoration requirements for the loss of up to two elements can be met by Hydro One.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following work is part of Hydro One approved sustainment business plan

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

7. RESULTS – NEEDS ASSESSMENT REPORT

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and following needs identified be further assessed as part of Local Planning:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the North & East of Sudbury Region ("Region") over the next ten years. 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 North & East of Sudbury Region 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. If localized wires only solutions do not require further coordinated regional planning, 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 Hydro One Inc ("Hydro One") on behalf of the North & East of Sudbury Region NA Working Group (Table 1). The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Working Group Participants for North & East of Sudbury Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Northern Ontario Wires Inc
4.	Hydro One Networks Inc. (Distribution)
5.	Hearst Power Ltd
6.	North Bay Hydro Inc.

2 Regional Issue / Trigger

The NA for the North & East of Sudbury Region 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 North & East of Sudbury Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the North & East of Sudbury Region over an assessment period of 2016 to 2026. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, 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.

North & East of Sudbury Region Description and Connection Configuration
The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

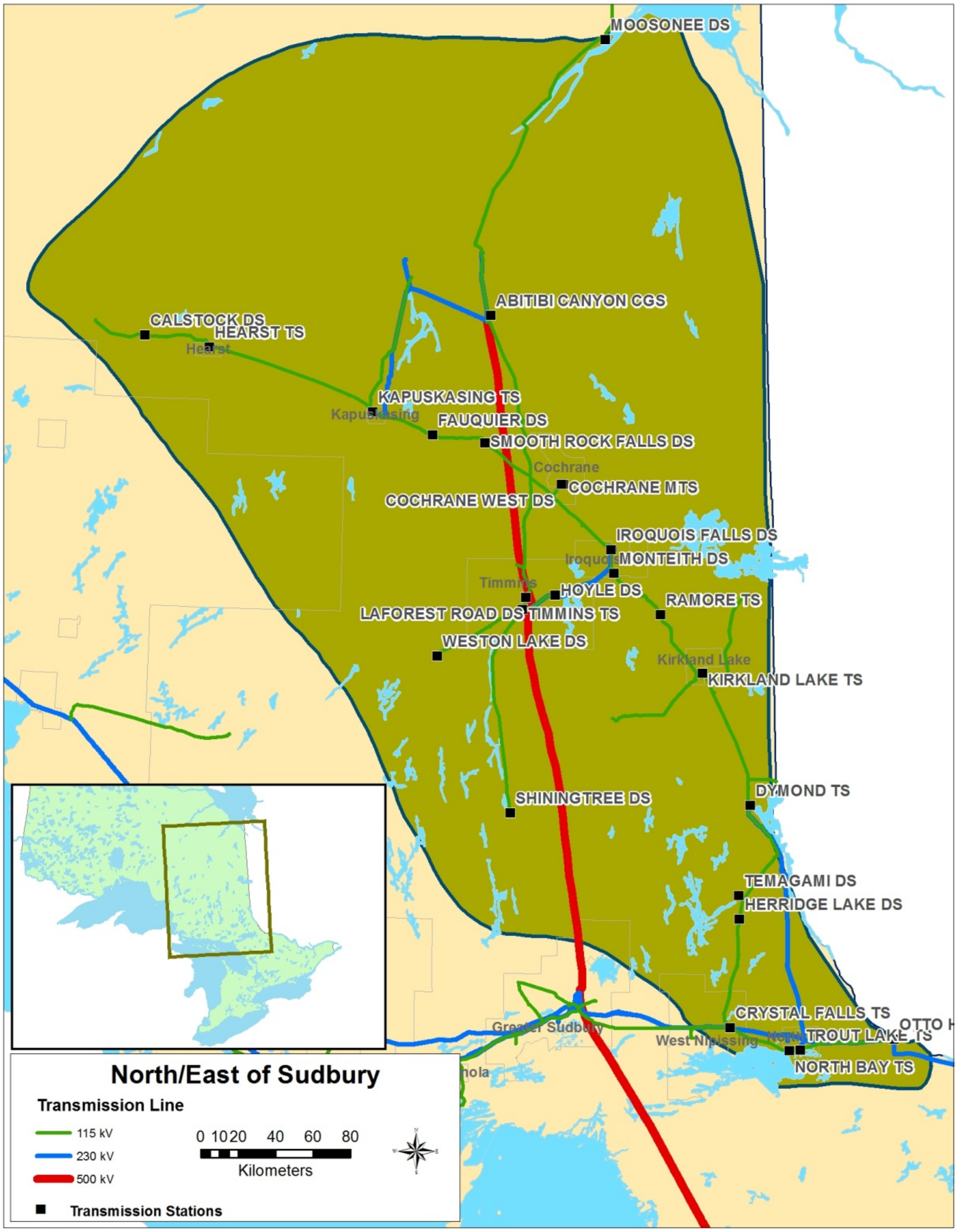

Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS.

This region has the following four local distribution companies (LDC):

- Hydro One Networks (distribution)
- Northern Ontario Wires Inc
- Hearst Power Ltd
- North Bay Hydro Distribution Ltd.

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS * Timmins TS Trout Lake TS Widdifield SS

***Stations with Autotransformers installed**

Table 2: Transmission Lines and Stations in North & East of Sudbury Region

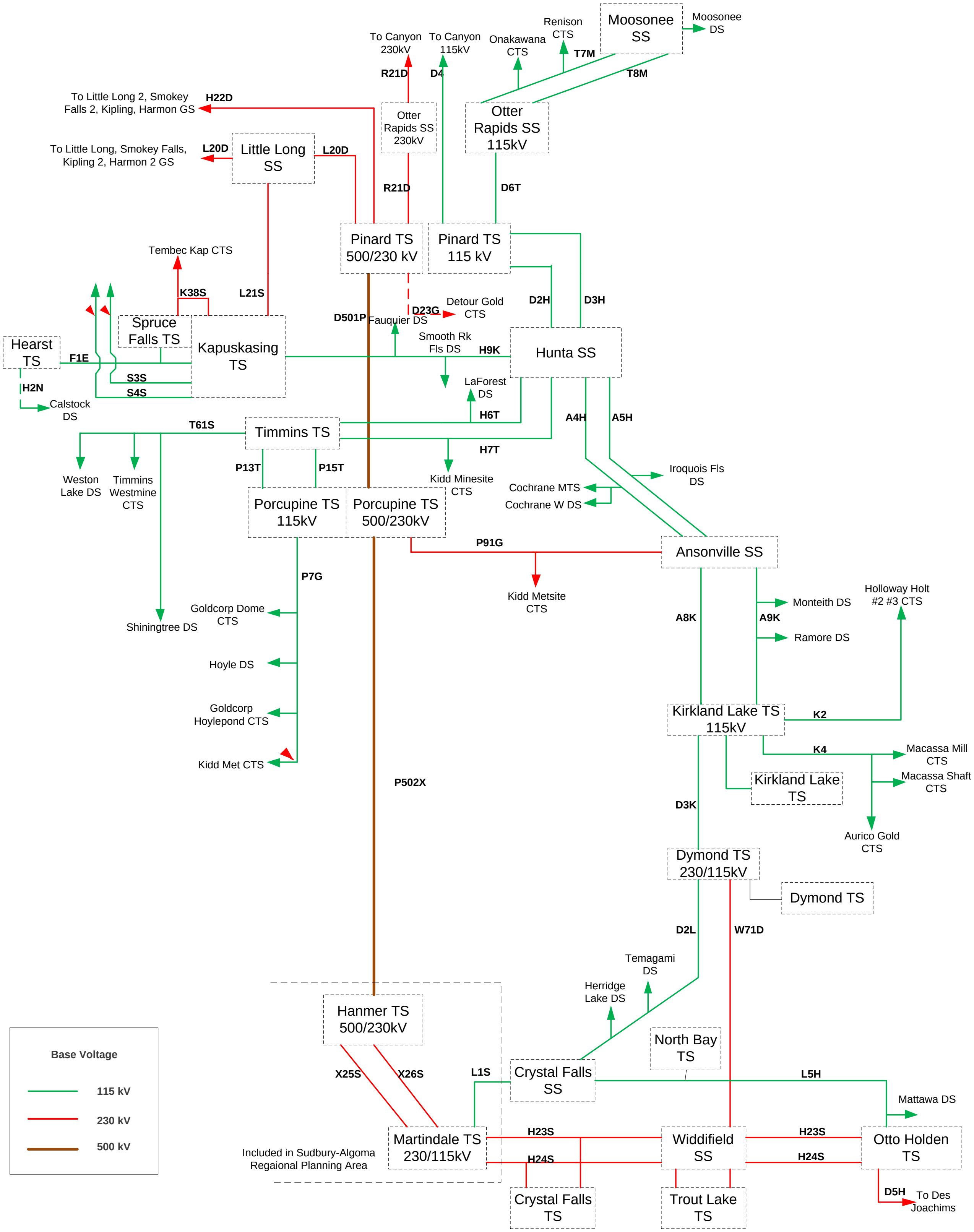

Figure 2 – North and East of Sudbury Regional Planning Electrical Diagram

4 Inputs and Data

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

- IESO provided:
  - i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  - ii. List of existing reliability and operational issues
  - iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2026) Note: 2026 gross load values were extrapolated from 2025 if required.
- 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.

Load Forecast
As per the data provided by the Working Group, the gross load in region is expected to grow at an average rate of approximately 0.7% annually from 2016-2026.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.04% annually from 2016-2026.
Note: Extreme weather scenario factor at 1.057 assessed over the study term.

5 Needs Assessment Methodology

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

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region's LDCs
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. Accounting for (2), (3) above, the gross load forecast and 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 are analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report. A gross and net region-coincident peak load forecast was used to perform the analysis.

5. Review impact of any on-going and/or planned development projects in the Region 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 winter 10-Day Limited Time Rating (LTR). Summer LTR ratings also were reviewed against the station load forecasts over the study period.
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.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. Note: This criterion was put in place after the 500 kV Northeast system was built and as such, the system was not originally designed to respect this criteria for the loss of the 500 kV circuits P502X or D501P. Currently the loss of either these circuits can result in the loss of more than 150 MW.
    - With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With up to two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

6.1 500/230kV Autotransfomers

The 500/230 kV transformers supplying the region are adequate for loss of single 500/230 kV unit.

6.2 500/115kV Autotransfomers

The 500/115kV transformers supplying the region are adequate for loss of single unit.

6.3 230/115kV Autotransfomers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

6.4 Transmission Lines and Ratings

The 500kV and 230 kV circuits supplying the region are adequate over the study period for the loss of a single 500kV or 230 kV circuit in the Region.
As per section 7.2 below – the 115kV H9K circuit may experience thermal overloads and will be addressed as a bulk system issue outside of regional planning.

6.5 230 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 station winter peak load forecast provided by the Working Group. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario

7 SYSTEM RELIABILITY, OPERATION AND RESTORATION

7.1 Performance

The areas of Timmins, Dymond and Abitibi Canyon have experienced severe weather patterns over the last 5 years causing periodic increases of both momentary and sustained outages which have been highlighted by the IESO. The region (including the three mentioned above) does not have circuit performance outliers which would fall below customer delivery point performance standards set forth by the Ontario Energy Board.

Hydro One continually monitors performance of supply stations, and high voltage circuits and will make the necessary steps to address the problem should this issue persist.

7.2 Restoration

Depending on system conditions, the loss of P502X may result in the greatest amount of load lost through North East LR/GR special protection schemes. Based on the load levels in the study period of this assessment, load can be restored within the 30 minute, 4 hour and 8 hour time frames as required by IESO ORTAC Section 7.0. The maximum load which may be interrupted by configuration or load rejection due to the loss of two elements is up to 450MW which is below the ORTAC requirement of 600MW. (loss of P502X with D3K out of service, or vice versa)

7.3 Thermal overloading on H9K section

Under high generation scenarios, IESO has identified pre and post contingency overloads on the 115 kV circuit H9K between *Tembec SRF x H9K 127A* junction.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.4 Congestion on D3K, A8K, A9K, H6T and H7T

Under high generation scenarios, IESO has identified there may be congestion on D3K, A8K, A9K, H6T and H7T circuits.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.5 Kapuskasing and Calstock Area Generation

Non-utility Generator ("NUG") contracts are reaching end of term for the Kapuskasing and Calstock Generating Stations. The NUG Framework Assessment Report [1] indicated that local reliability and congestion issues may require further study as this pertains to contracted generation facilities. This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.6 Outage Condition Resulting in P15/P7G/T61S radially connected to Timmins

The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus.
This scenario will be addressed in the next stage of regional planning.

7.7 Ansonville T2 or D3K outages

With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at Kirkland Lake TS. This scenario will be addressed in the next stage of regional planning.

8 Aging Infrastructure and Replacement of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. during the study period. At this time the major committed system investments are;

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

9 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, it is further recommended that voltage regulation issues at Timmins TS and Kirkland Lake TS be best addressed by wires options solution thru local planning led by Hydro One:

10 NEXT STEPS

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and the two voltage regulation needs identified in Section 7 be further assessed as part of Local Planning to be entitled:

<u>Timmins TS / Kirkland Lake TS – Voltage Regulation Issues</u>

11 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

12 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
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
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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NEEDS ASSESSMENT REPORT

Region: Renfrew

Revision: Final
Date: March 11, 2016

Prepared by: Renfrew Study Team

Transmission

Distribution

Peterborough to Renfrew Region Study Team Organization
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Renfrew 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.

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	Renfrew Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	October 23, 2015	**END DATE**	March 11, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Renfrew 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 Renfrew 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 Renfrew Region belongs to Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 11, 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 Board.

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 to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability, which covers station loading, thermal, and voltage analysis, system reliability, and assets approaching end-of--life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Renfrew Region. The information included: existing information from planning activities already underway, 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-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2015 to 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. Station Capacities

- All stations in the region have sufficient capacity to supply the loads in studied period under normal and single contingency condition.

B. Transmission Circuits Capacities

- All transmission circuits have sufficient capacity under normal and single contingency condition.

System Reliability, Operation and Restoration Needs

There are no transmission system reliability issues and no operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, loss of one element will not result in load interruption for more than 150MW by configuration.

All load within the region can typically be restored within eight hours as per the ORTAC requirement for loads under 150 MW.

In recent years, maintenance activity in the region with respect to vegetation management has been enhanced resulting in an improvement in reliability and/or load restoration.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at three stations will increase station capacities. Further details of these investments can be found in Section 3.2 of this report.

7. RECOMMENDATIONS

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

- Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

- No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Renfrew 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 Board".

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Renfrew 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 Renfrew Region Needs Assessment study team. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1 Study Team Participants for Renfrew Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Networks Inc. (Distribution)

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Renfrew 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 October 23, 2015 and was completed on March 4, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Renfrew Region over an assessment period of 2015 to 2024. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuits 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 Renfrew Region Description and Connection Configuration

The Renfrew Region includes all of Renfrew County. Fig.1 shows the map of the Region. The 2014 peak load in this Region was 124 MW.

The electricity supply to the region is mainly through one 230kV circuit X1P and three 115 kV radial circuits: D6, X6 and X2Y (Fig.1). The 115kV circuits are supplied by 230/115 kV autotransformers at Chenaux Transformer Station (TS) from the East and Des Joachims TS from the West. A normally opened 115kV switch at Pembroke TS isolates the East and the West sides of the region.

The Renfrew Region is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast. The distribution system in this region consists of voltage levels 44 kV, 13.8 kV, and 12.5 kV. The main generation facilities in the Renfrew Region are Chenaux Generation Station (GS) of 143.7 MW (according to Transmission Connection Agreement, applicable thereafter), Mount Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW.

Hydro One Networks Inc. (Distribution) is the main customer in the area. Other Local Distribution Companies (LDC) supplied from electrical facilities in the Renfrew Region includes Ottawa River Power Corporation and Renfrew Hydro Inc, both are embedded into Hydro One's distribution system. Major transmission connected customers in the area include Canadian Nuclear Laboratories and Magellan Aerospace.

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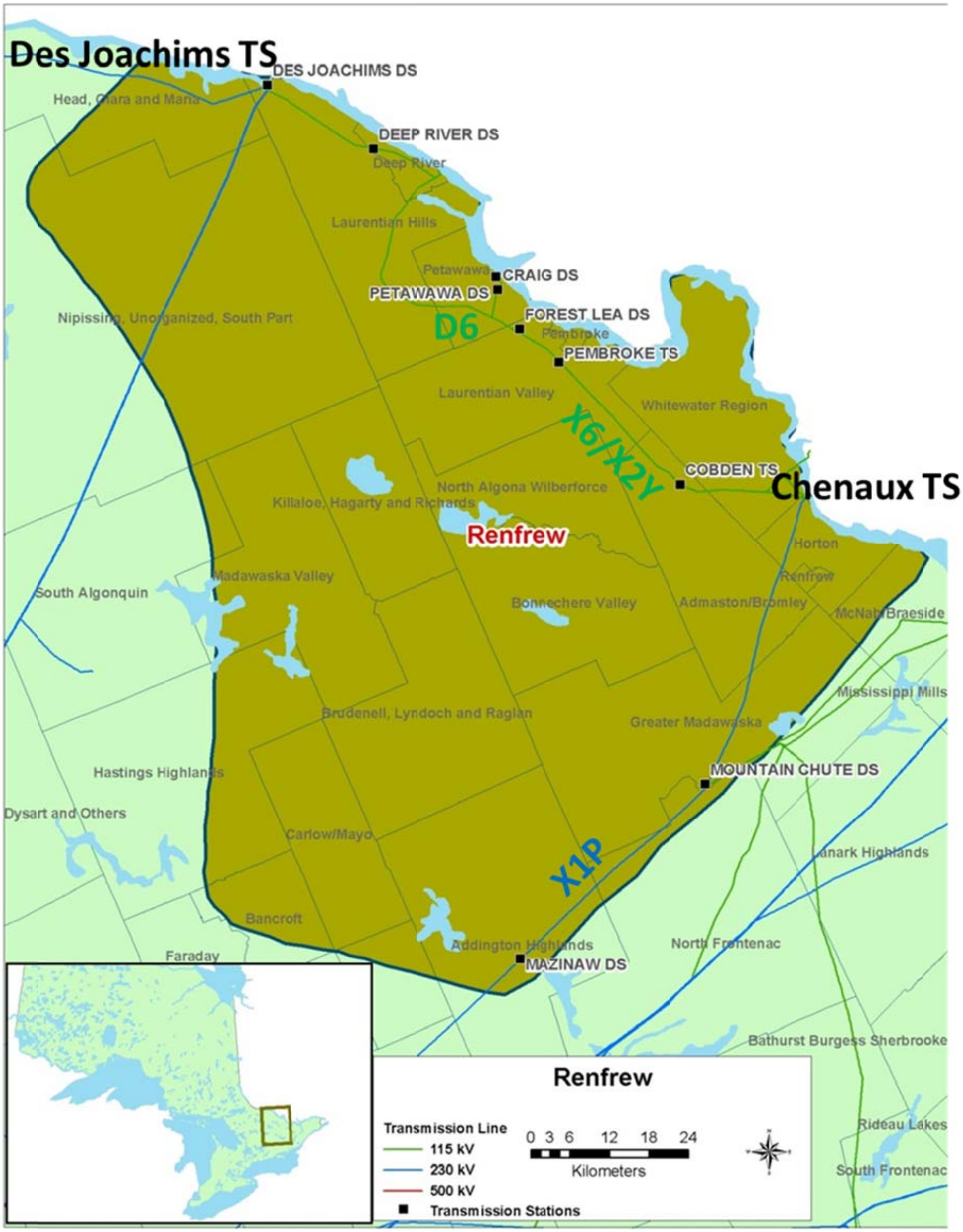

Fig. 1 Renfrew Region Map

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Fig. 2.

- Des Chenaux TS is a major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y.

- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Magellan Aerospace CTS. The two circuits are coupled via and only via Pembroke 44kV bus tie breaker

- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation units connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.

- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Chalk River Customer Transformer Station (CTS).

- All the 115kV circuits X6/X2Y/D6, all the 115kV stations tapped to the 115kV circuits, and all the autotransformers at Des Joachims TS and Chenaux TS are not NERC BES element.

- Bryson GS of Hydro Quebec can be radially connected to Renfrew region via X2Y.

- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew Region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region. The DS typically has load less than 1MW.

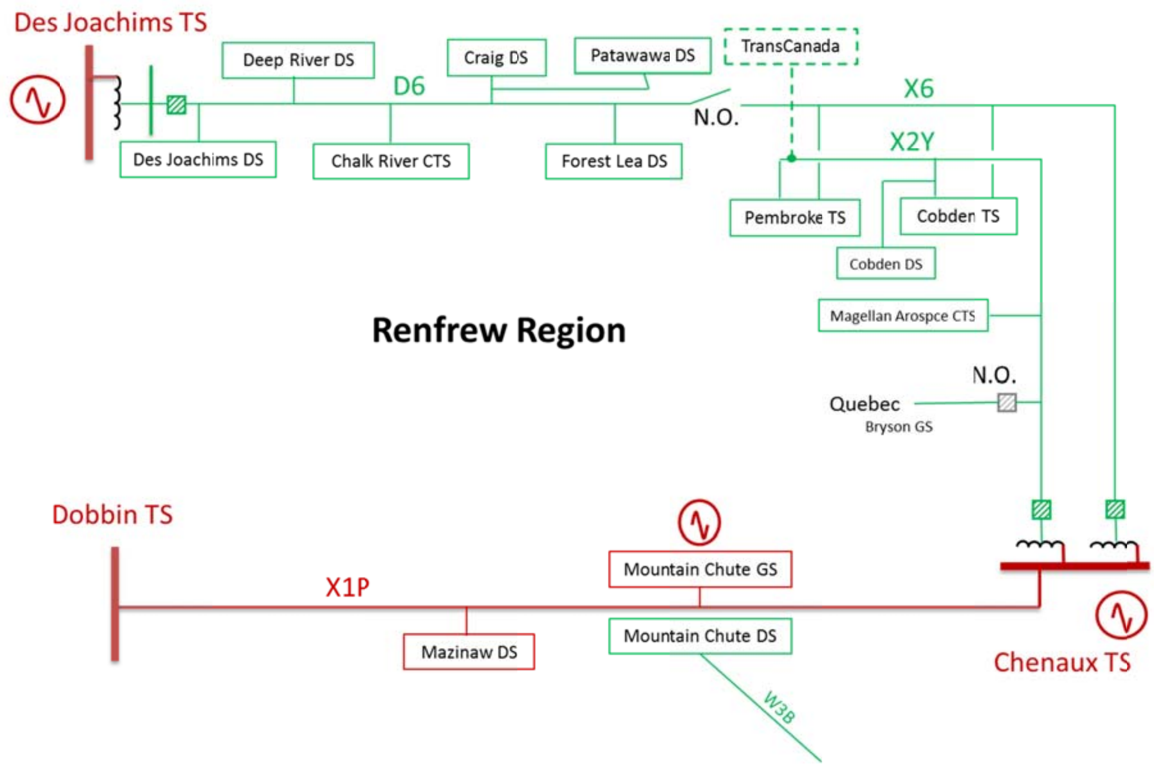

Fig. 2 Single Line Diagram – Renfrew Region

3.2 Planned Work in Renfrew Region

Following work has been planned in Renfrew Region:

- Two step-down transformers at Deep River DS (T1 and T2) will be replaced due to end-of-life for an in service date of end of 2016. This will also result in uprating the transformer capacity from 10MVA to 12.5MVA.
- Mountain Chute DS transformer will be replaced due to end-of-life with an in service date of end of 2016. This will also result in uprating the transformer capacity from 3MVA to 12.5MVA.
- Chenaux TS 230/115kV autotransformers T3 and T4 will be replaced due to end-of-life with an in service date of end of 2018. The existing units are rated 78MVA and 115MVA respectively. The new T3/T4 will both have continuous rating of 125MVA. This is a transmission pool investment and LDCs are not expected to pay.
- A TransCanada pump station is expected to tap to X2Y at Pembroke TS (Fig.2). The peak load of the station is 19.4MW. Two capacitor banks, each rated at 10Mvar, are assumed to be in service with the load. The station is expected to be in service in 2020.

4 INPUTS AND DATA

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

- IESO provided:
  i. Historical regional coincident peak loads and station non-coincident peak loads between 2012 and 2014
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and future Distributed Generation (DG) data
- LDCs provided historical (2012-2014) net loads and gross loads forecasts (2015-2024) for each station.
- The study team could not get response from Chalk River CTS and Magellan Aerospace CTS regarding their load forecasts. It is assumed that the loads at these two stations would not increase over the study period.
- Any relevant planning information, including planned transmission and distribution investments are provided by the transmitter and LDCs.

As per the data provided by the study team, the net load (i.e. after DG and CDM adjustment) in the Renfrew Region is expected to grow at an average rate of approximately 0.6% annually from 2015 to 2024.

5 ASSESSMENT METHODOLOGY

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

1. The Region typical typically has winter peak. Fig. 3 plots the load profiles at Pembroke TS and Cobden TS from July 2013 to July 2015, which evidences the winter peaking characteristics. Therefore this assessment is based on winter peak load.

2. Loads forecasts are provided by the LDCs, i.e., Hydro One Networks Inc. (Distribution) in this case.

3. Average gross load growth rate at each station is calculated from the LDC's load forecast. The growth rates are then applied to the 2014 coincidental winter peak load to generate each year's coincidental peak load.

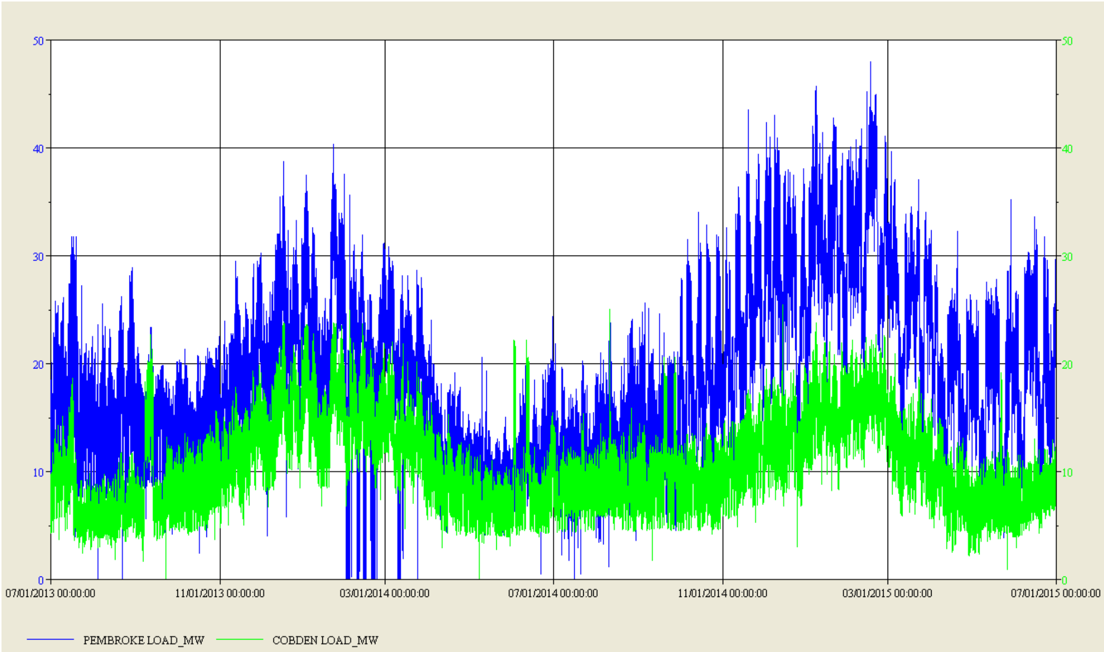

Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

4. The 2014/15 winter was already extremely cold; therefore no extreme weather adjustment was used.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and planned development projects in the Region during the study period. This includes:

   - A new 19.4MW load is expected to connect to circuit X2Y at Pembroke in 2020. This Needs Assessment assumes that the load is in service.

7. Review and assess impact of any major elements planned to be replaced at the end of their useful life such as transformers, cables, and stations.

8. 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 and 95% lagging power factor for stations with low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Region is determined by the 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on 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. Projected coincidental peak loads are used in such assessment.
    - 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 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC). Des Joachims and Chenaux 115kV bus voltages are maintained between 122kV and 127kV according to established operation practice.
    - 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 time limits as per ORTAC criteria.

11. Full load transfers for restoration purposes are not mandatory requirement. Restorations of load between Chenaux TS and Des Joachims TS via D6-X6 load transfers are performed to the extent possible.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Renfrew Region.

6.1 Transmission Capacity Needs

This is to assess a) adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and b) adequacy of transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

6.1.1 Station Adequacy Assessment

Non-coincident peak load at each station is compared against corresponding transformer maximum continuous rating or 10-day LTR if the continuous rating is exceeded. The peak loads are all forecasted to happen in 2024. Table 2 compares the net peak load against transformer ratings at each station. It can be seen that all stations are adequate to supply the loads in studied period.

Table 2 Station Adequacy Assessment

Station	Transformers	Net Peak Load (MW)	Transformer Rating/LTR* (MW)
Cobden DS	T3	7.2	11.3
Cobden TS	T1/T2	27.1	37.5
Craig DS	T1/T2	12.2	15.9
Deep River DS	T1/T2/T3	11.1	23.8
Des Joachims DS	T1	3.3	11.3
Forest Lea DS	T1/T2	9.2	9.9
Mazinaw DS	T1	3.4	5.4
Mountain Chute DS	T1	1.0	11.3
Pembroke TS	T1/T2	49.1	49.6
Petawawa DS	T1/T2	14.3	14.8
Chalk River CTS***		10	N/A
Magellan Aerospace CTS***		3.1	N/A
Chenaux TS	T3/T4	101.7**	112.5
Des Joachims TS	T6/T7	57.1	112.5

*: LTR is listed only if the peak load exceeded transformer continuous rating
**: Including 19.4MW new load, all station MVAs add up arithmetically
***: Load customer owned transformers, capacity not assessed in this study

6.1.2 Transmission Facility Adequacy Assessment

Under normal condition with all elements in service and the D6-X6 in-line switch open, the study found that:

- All transmission circuits supplying the Region, namely D6, X6, X2Y and X1P have adequate capacity over the study period.

The projected regional peak loads can be supplied even if the local generations at Des Joachims GS and Chenaux GS are out of service. In the X6/X2Y corridor, loss of one circuit (including breaker failure condition to cause additional loss of Chenaux generation) would not cause overload or under-voltage on the accompanying circuit. .

6.2 System Reliability, Operation and Restoration Review

- The Region's total coincidental peak load is less than 150MW, therefore load loss violation due to configuration does not apply in this assessment.
- All loads are expected to be restored within 8 hours.
- The most critical contingency in the Region would be loss of 230kV circuit X1P which would produce an island at Chenaux. Stable islanding operation might be

achieved depending on pre-contingency flow and generation rejection arming. Reliability data recorded 13 X1P non-planned outages in past ten years, among which seven events show stable islanding operations before the system was paralleled back to the grid. In another two events the island collapsed after more than one hour of operation. The performance is expected to be unchanged in the study period.

- Studies show that under this contingency, Des Joachims TS may not be able to radially supply all the loads in the Region, under peak load conditions.
- Due to the fact that the loads are supplied via radial circuits and the Region is prone to storms, extended outages on D6 were experienced in the past (in 2011 for example). Further, outage analysis indicated that the most common cause for sustained outages was under severe storm. This issue cannot be addressed by building additional line in the same right-of-way. As a result, improved vegetation management and outage responses have effectively reduced sustained outages considerably in recent years. Table 3 lists sustained outage records of D6 in past five years.

Table 3 Outage Records of D6 from 2011 to 2015

Year	No. of Sustained Outages	Cumulative Duration (min)	Causes
2015	1	367	Conductor Broken
2014	1	5	Human Error
2013	3	1381	Isolated Electrical Storm
2012	1	1341	Tree Contact
2011	4	7792	Tree Contact

Studies show that under D6 terminal outage at the Des Joachims terminal, load can be restored by transferring D6 to Chenaux TS 115kV via X6 supply. Note, there is a maximum limit of 125 MW, which is the peak regional load in 2015, that can be supplied radially from Chenaux.

a) The following potential needs will be monitored and assessed in the next Regional Planning cycle for the Renfrew Region:

- Hydro One and the LDCs will continue to monitor and assess the load restoration performance under X1P and D6 outages.

- Major Hydro One facilities and equipment are continually monitored to ensure their safe and reliable operation. Circuit X1P is one of these facilities and, as such, its performance is monitored by Hydro One's Ontario Grid Control Centre (OGCC) in Barrie. OGCC's records will be reviewed regularly to ascertain the adequate performance of this circuit. The next planning cycle will take place in five years however, if the performance of X1P fall below adequate levels the Hydro One will undertake to assess and address this issue with the LDCs.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Section 3.2 lists the sustainment initiatives that are currently planned for the replacement of any aged transformers. There are no major line replacement plans scheduled in the near term in this region.

7 RECOMMENDATIONS

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

> No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region. Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

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 18-Month Outlook: January 2016 – June 2017
iii) 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 FORECAST

Table A-1: Station Net Load Forecast (MW)

Transformer Station Name	Rating (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	11.3	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.1	7.2
Cobden TS T1/T2	37.5	25.8	25.9	26.0	26.0	26.2	26.5	26.6	26.8	26.9	27.1
Craig DS T1/T2	15.9	11.2	11.3	11.3	11.4	11.6	11.7	11.9	12.0	12.1	12.2
Deep River DS T1/T2/T3	23.8	10.9	11.0	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1
Des Joachims DS T1	11.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Forest Lea DS T1/T2	9.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.2	9.2
Mazinaw DS T1	5.4	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4
Mountain Chute DS T1	11.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Pembroke TS T1/T2	49.6	46.0	46.3	46.5	46.7	47.1	47.6	48.0	48.3	48.7	49.1
Petawawa DS T1/T2	14.8	12.8	13.1	13.2	13.4	13.6	13.8	13.9	14.1	14.2	14.3

Table A-2: Regional Coincidental Net Load Forecast (MW)

Transformer Station Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8
Cobden TS T1/T2	25.5	25.5	25.7	25.8	25.9	26.1	26.3	26.5	26.8	27.1
Craig DS T1/T2	11.1	11.2	11.3	11.3	11.4	11.5	11.6	11.8	11.9	12.1
Deep River DS T1/T2/T3	10.8	10.7	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.0
Des Joachims DS T1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Forest Lea DS T1/T2	9.0	9.0	9.1	9.0	9.0	9.0	9.1	9.1	9.2	9.2
Mazinaw DS T1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Mountain Chute DS T1	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS T1/T2	38.7	38.9	39.3	39.6	39.9	40.3	40.8	41.3	42.0	42.6
Petawawa DS T1/T2	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Total Regional Load	125.2	127.2	128.0	128.2	128.6	129.3	130.3	131.4	132.7	133.8

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IDENTIFYING ASSET NEEDS: ASSET MANAGEMENT APPROACH

1. INTRODUCTION

This Exhibit describes the overall methodology used by Hydro One to determine its sustainment investment plan. The approach set out in this exhibit enables Hydro One's transmission system to continue providing safe and reliable service. Hydro One's approach takes into account the following business objectives:

- Maintaining top quartile reliability by mitigating risk arising from asset deterioration;
- Minimizing the long-term costs of maintaining the reliability of the transmission system;
- Ensuring that compliance with the regulatory and reliability standards is maintained:
- Improving current levels of customer satisfaction;
- Driving towards an injury-free workplace: and
- Sustainably managing the environmental footprint of operations.

Hydro One's sustainment investment process informs both the scope and timing of sustainment investments.

Investment Process The investment plan is determined by a process that consists of the following steps:

1. It begins with a *review of the system*, with a focus on reliability performance and reliability risk, asset demographics and asset condition information. Reliability performance and reliability risk are discussed further in this exhibit. Asset demographics and asset condition are discussed further Exhibit B1, Tab 2, Schedule 5 as part of the

Asset Risk Assessment. Exhibit B1, Tab 2, Schedule 6 provides an overview of Hydro One's assets based on the assessment process.

2. *Additional factors* are then considered, including equipment performance, criticality, economics and utilization. Subsequently other factors are also included, such as obsolescence, environmental risks and requirements, compliance obligations, equipment defects, health and safety considerations and customer needs and preferences. The use of these factors is described in Exhibit B1, Tab 2, Schedule 5 as part of the Asset Risk Assessment. Exhibit B1, Tab 2, Schedule 6 provides an overview of Hydro One's assets based on the assessment process.

3. These factors enable the *creation of a portfolio of potential investment candidates*. These investments may include either individual or integrated projects that address multiple asset needs. Exhibit B1, Tab 3, Schedule 2 further explains the integrated projects.

4. An *optimization* exercise is then undertaken to consider resource constraints, execution capability, pacing, and customer rate impact (Exhibit B1, Tab 2, Schedule 7).

5. The process concludes with an *assessment of the outcome* of the optimization exercise on reliability risk. The reliability risk model discussed in detail further in this exhibit is used to help determine pacing of investments.

Hydro One also utilizes Expected Service Life ("ESL" defined as the average time in years that an asset can be expected to operate under normal system conditions) to assist in identifying assets as candidates for investment in the Asset Risk Assessment (ARA) process, described in Exhibit B1, Tab 2, Schedule 5.

The resulting investment plan strikes a balance between the various asset and customer needs. Figure 1 below illustrates the different expenditures by outcome for the 2017 and 2018 investment plan.

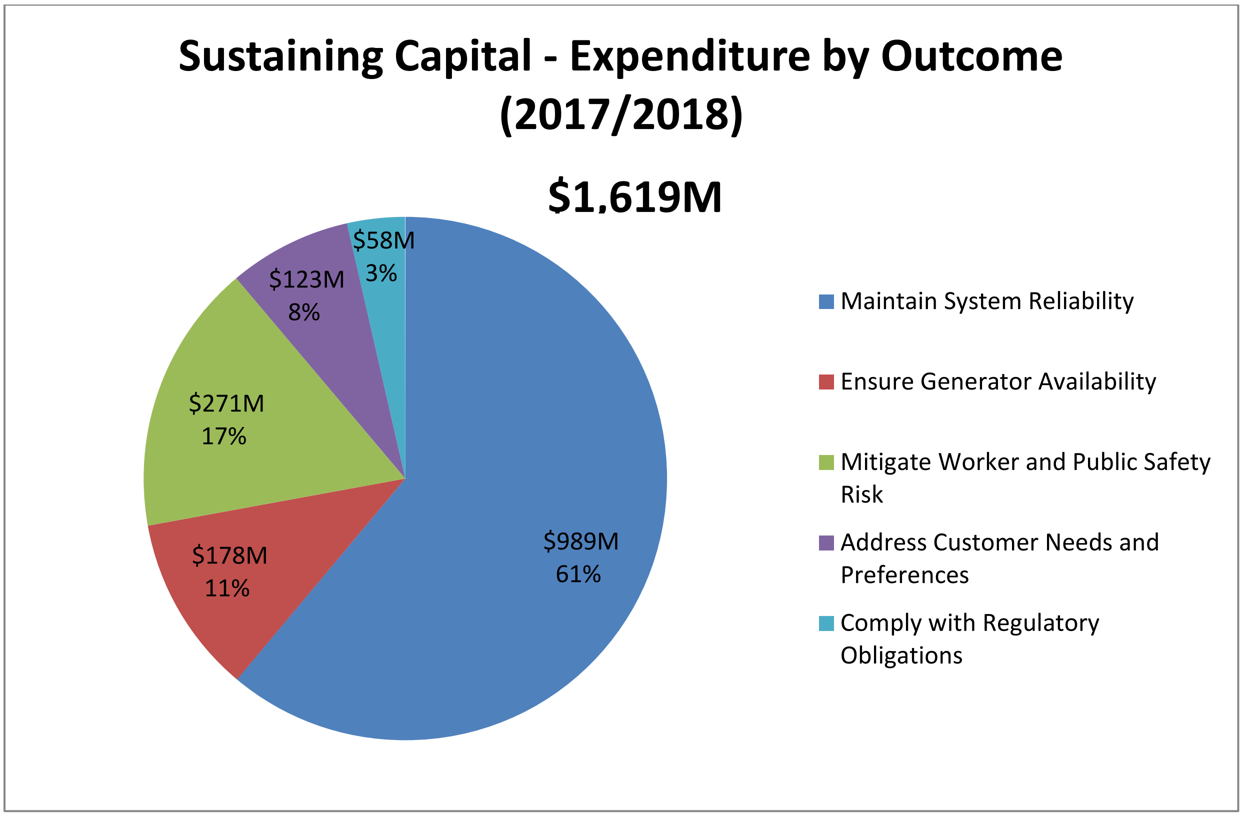


Figure 1: Sustaining Capital – Expenditure by Outcome

Sixty One per cent (61%) of the expenditures are directly related to reliability. Safety and regulatory compliance driven investments are generally non-discretionary. Investments related to generation are paced to enable overall Ontario grid reliability and adequacy in anticipation of the refurbishment or retirement of major nuclear generation facilities.

Hydro One executes this capital work, as well as its maintenance programs, as detailed below and in Exhibit B1, Tab 4, Schedule 1.

There are two types of sustainment investments - Sustainment OM&A and Sustainment Capital, both of which are described below.

1.1 Sustainment OM&A

Sustainment OM&A comprises investments required to maintain the functionality and performance of existing transmission assets. Hydro One employs a life cycle management approach, to optimize performance and costs over an asset's life and meet the objectives of Hydro One's asset strategy. A full explanation of maintenance and operating expenses is provided in Exhibit C1, Tab 2, Schedule 2.

1.2 Sustainment Capital

Sustainment capital investments are required to replace or extend the life of transmission components for technical and/or economic reasons in line with Hydro One's asset strategy objectives. Sustainment capital investments address risks associated with the deterioration of the transmission assets. A full explanation of capital investments is provided in Exhibit B1, Tab 3, Schedule 2.

2. SCOPE AND TIMING OF INVESTMENTS

The scope and timing of investments are considered in the investment process. The scope is considered in step three and timing is considered in steps four and five. The timing of the investments is influenced by the following factors.

- System-wide assessments of reliability performance and reliability risk;
- Asset condition;
- Customer needs and preferences; and
- Sustainment forecast and external constraints.

In addition, Hydro One also employs benchmarking, such as the Transmission Total Cost Benchmarking study, to compare planned levels of capital and OM&A investments against peer transmission companies. The Total Cost Benchmarking study is found in Exhibit B2, Tab 2, Schedule 1.

3. SYSTEM RELIABILITY PERFORMANCE AND RELIABILITY RISK

Transmission system reliability performance can be measured in terms of frequency and average duration of forced delivery point interruptions that interrupt power supply to customers, and equipment unavailability which is the amount of time that major transmission equipment is out of service due to forced outages.

Reliability performance is typically measured in Canada by T-SAIFI and T-SAIDI, which reflect the average frequency and duration of interruptions per delivery point on the transmission system. Hydro One employs these metrics to measure performance of the transmission system and has maintained relatively constant system-wide reliability performance over the past 10 years, placing in the 1st quartile amongst its Canadian peers. Hydro One's performance metrics are shown in Figures 8 through 11, found in Exhibit B1, Tab 1, Schedule 3.

While T-SAIFI and T-SAIDI are important metrics, they are lagging indicators of future transmission system reliability performance. By the time these metrics worsen, considerable equipment issues will have already developed. It is therefore important to target leading indicators such as reliability risk. Existing asset condition provides a static view which is insufficient to predict future reliability, as assets will continue to deteriorate over time. In addition, it will take considerable time to plan, design and construct transmission assets to remedy the deteriorated equipment.

Hydro One has modified its asset management approach to include reliability risk as a leading indicator of future transmission system performance. Hydro One's approach has been informed by the development of this approach in other jurisdictions. This approach is new for Hydro One and the company intends to further develop the reliability risk approach and refine its application in the sustainment planning process.

3.1 Reliability Risk

Equipment unavailability is a measure of the amount of time that power equipment is not available for use on the system due to forced outages. As shown in Figures 12 and 13 in Exhibit B1, Tab 1, Schedule 3, station equipment unavailability has continued to trend upward in the recent past while line equipment unavailability is expected to trend upwards based on asset condition assessments and the demographics of lines assets. While equipment unavailability does not necessarily lead to customer interruptions, due to planned redundancy on Hydro One's transmission system, it is a leading indicator of future reliability issues.

Equipment reliability risk similarly serves as an indicator of the potential for future reliability issues. Hydro One has historically taken a risk management approach to preventing equipment failure, but has not previously attempted to quantify reliability risk. Hydro One has recently developed a system risk model to quantify and understand the relative level of reliability risk of its transmission fleet. The risk model's output is an overall risk metric, which is indicative of the risk of reliability improvement or degradation at various investment levels.

Reliability risk is a metric which gauges the extent of reliability risk improvement or degradation at various investment levels. It is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure or replacement.

Reliability risk is used by Hydro One in its asset management process to gauge the impact of its investments on future transmission system reliability. It also provides a directional indicator to inform the appropriate level and pacing of sustainment investments. The reliability model is not used to identify specific asset needs and investments. These are determined by condition assessments and other asset specific information, as described in Exhibit B1, Tab 2, Schedule 5.

3.2 Reliability risk modeling approach

Reliability risk is modelled using the relationship between asset demographics, historical asset failures and the impact that equipment has on reliability. Hydro One's risk model focuses on lines, transformers and breakers, due to their large contribution to reliability risk and criticality to the system. Calculating reliability risk based on the interruption durations attributable to these asset classes creates a measure of the substantial portion of the reliability risk on the transmission system.

The output of the risk model is a measure of the system reliability risk resulting from planned investments relative to a baseline. The model considers both the expected impact of asset replacement and the continued aging and deterioration of existing assets. Additional details on the structure and application of the reliability risk model are available in Appendix 1 of this schedule.

Hydro One has used this model to gauge the expected reduction in risk achieved through the sustainment capital investments planned for the 2017 and 2018 test years. Table 1 below summarizes the expected relative decrease in risk, for each critical asset class and for the system as a whole, as a result of the 2017 and 2018 investment plan. For comparison the table also provides the relative increase in risk which will occur if no assets were replaced in the two year period.

Table 1: Relative Change in Reliability Risk

	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, as per proposed investment	**Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, without investment**	**% of Interruption Duration***
Lines	-2%	11%	69%
Transformers	-9%	14%	9%
Breakers	1%	17%	6%
Other[1]	-	-	16%
Total*	**-2%**	**10%**	

* Total is calculated by weighting the change in risk by the asset class' contribution to interruption duration.

4. ASSET CONDITION

At a fleet level, asset age is used as a proxy for the probability of asset failure and the need for replacement. Quantitative data demonstrates the historical relationship between asset age and failure. This data has informed Hydro One's reliability risk model. However, as noted above, specific investment decisions are not based on age, but through the Asset Risk Assessment process described above and in Exhibit B1, Tab 2, Schedule 5.

[1] Represents all other assets; risk is assumed to be flat over the investment planning horizon for these assets

4.1 Relationship between Maintenance Expenditures and Capital investment

Hydro One has relied on maintenance programs to extend the lifespan of assets by continually addressing asset condition deficiencies, where practical, as a means of deferring large capital expenditures. As a result assets are being operated beyond their expected service life ("ESL"). Although this approach defers capital investments, it increases maintenance costs and the risk that assets will fail, deteriorate significantly or become obsolete as spare parts and manufacturer support is becomes unavailable.

The following examples illustrate situations where these risks were manifest:

- Elgin TS and Horning TS were constructed in Hamilton in 1968 and 1967 respectively. Although the equipment at both stations was in a deteriorated condition, Hydro One continued to keep them operating through continual corrective maintenance. Capital investments to refurbish these stations were planned in 2015 and 2016 respectively. However, both stations suffered multiple equipment failures in early 2016, involving metalclad switchgear and transformers. These failures caused reliability and public safety concerns.

- In 2015, significant equipment failures also occurred with Bridgman TS (Toronto), built in 1952, and Frontenac TS (Kingston), built in 1938, due to deteriorating assets. These failures caused reliability and public safety concerns due to their locations. In the case of the Frontenac failure, Kingston and surrounding areas lost power for over 12 hours.

As a result of incidents like these, Hydro One is focusing on upgrading stations and increasing the pace of replacing major power equipment to maintain reliability performance.

5. CUSTOMER NEEDS AND PREFERENCES

Customers' needs and preferences are considered in the investment planning process set out above. Hydro One undertook a concerted effort to gather customer feedback in advance of this filing, engaging in a consultation process which is described in detail in Exhibit B1, Tab 2, Schedule 2.

Reliability emerged as an important concern for many customers in the consultation. Several customers reinforced the nature and extent to which interruptions impact their business. For example customers indicated “for one mine a one-day outage can cost tens of millions in lost productivity. For one paper mill, a ten-second interruption takes 8-10 hours to come back online and costs $500,000 to $1 million” (Exhibit B1, Tab 2, Schedule 2, Attachment 1).

Another common theme from customers was the relative impact of unplanned outages versus planned outages on their operations:

- “Every time there is an unplanned outage, even if we are back online in 15-20 minutes it’s a 2 hour interruption which is a $100,000 cost” (Exhibit B1, Tab 2, Schedule 2, Attachment 1).

- “It’s the unplanned outages. That’s what kills us. You drop as much as a frequency and we’re down for 16 to 24 hours. You measure it being out for a second and I’m out for a day. We can deal with the planned. The unplanned stuff, depending on how and where it hits we can be out for a day” (Exhibit B1, Tab 2, Schedule 2, Attachment 1).

The consultation feedback was also useful in assessing customer views on reliability risk and planned investment levels. Customers for the most part indicated that they expect Hydro One to be more proactive in addressing current and emerging reliability risk (Exhibit B1, Tab 2, Schedule 2, Attachment 1), and some customers criticized Hydro One for not spending sufficiently on sustainment capital historically (Exhibit B1, Tab 2, Schedule 2, Attachment 1). This feedback is also consistent with the results of Hydro One's customer survey, in which customers indicated concern with reliability and power quality (Exhibit B1, Tab 2, Schedule 2).

Hydro One also sought feedback from customers on a range of investment levels, represented by three scenarios that translated into different rate impacts and changes in reliability risk. Customers generally indicated a desire for maintained or reduced reliability risk, consistent with a higher level of capital investment.

Hydro One considered the feedback obtained during customer consultations in its investment plan.

6. SUSTAINMENT FORECAST AND EXTERNAL CONSTRAINTS

In developing its five year transmission system plan, Hydro One considered several key internal and external execution related factors while developing the level and the pacing of investments:

- Work execution capabilities;
- Expected future asset replacement needs in 2022 and beyond; and
- Outage constraints related to planned investments affecting generation on the system.

Hydro One has made significant investments in development capital from 2009 to 2012 to comply with government policy related to renewable energy and to increase system capacity to facilitate changes in the generation mix, including the Bruce to Milton 500 kV double circuit line, which was completed in 2011. While this work was necessary to further the energy objectives of the Province, sustainment investments were deferred.

The ESL profile of Hydro One's asset base suggests that significant sustainment capital will be needed between 2016 and 2030 in order to prevent an increase in reliability risk. Figures 2, 3, and 4 below show the demographic distribution of transformers, breakers and conductors currently in service on the transmission system. A sizable portion of each critical asset class is operating beyond expected service life, contributing to an increase in reliability risk. Specifically, 28% of transformers, 9% of breakers and 19% of conductors are currently operating beyond their normal expected service lives.

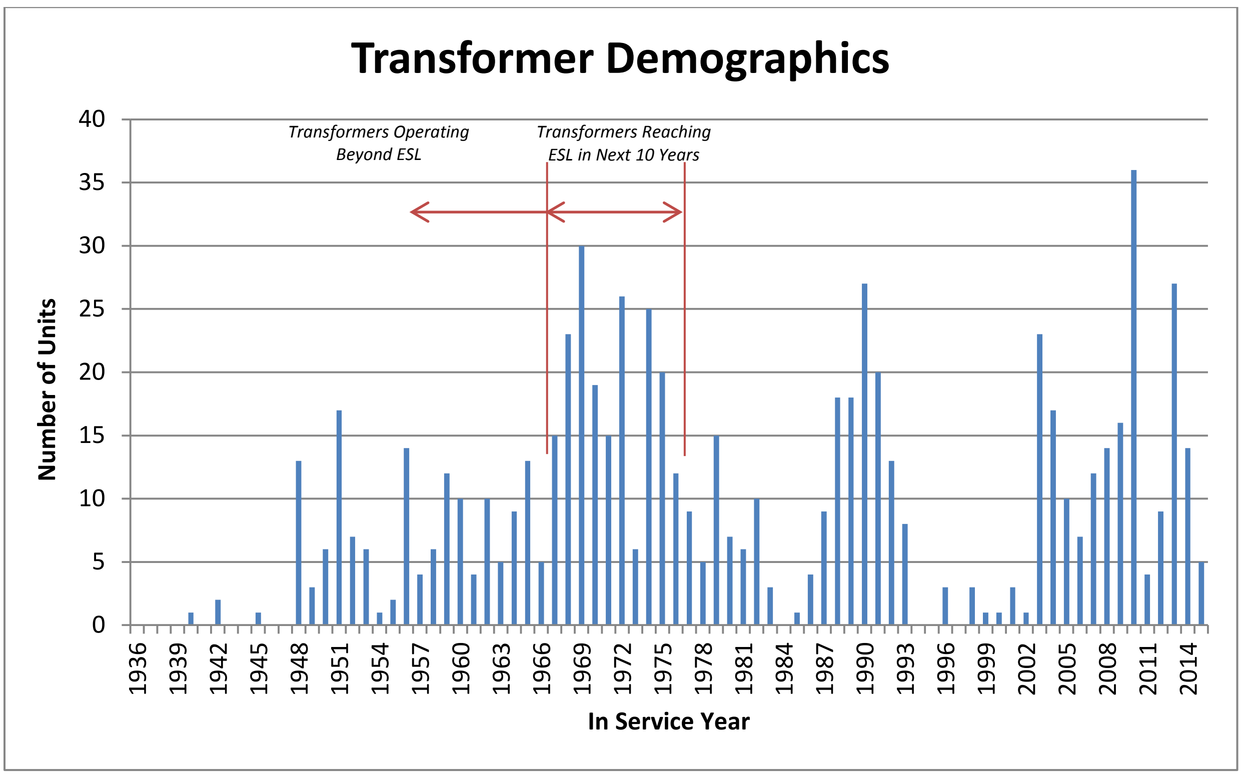


Figure 2: Transformer Demographic Distribution

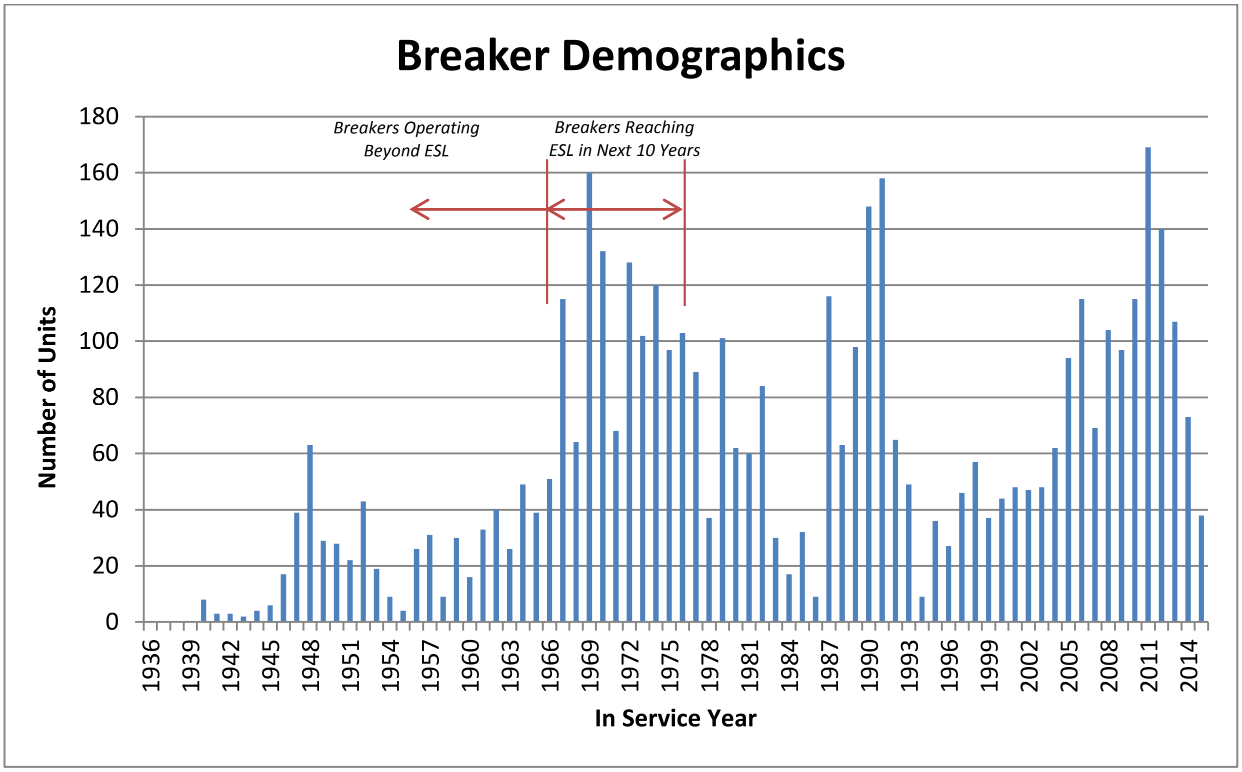


Figure 3: Circuit Breaker Demographic Distribution

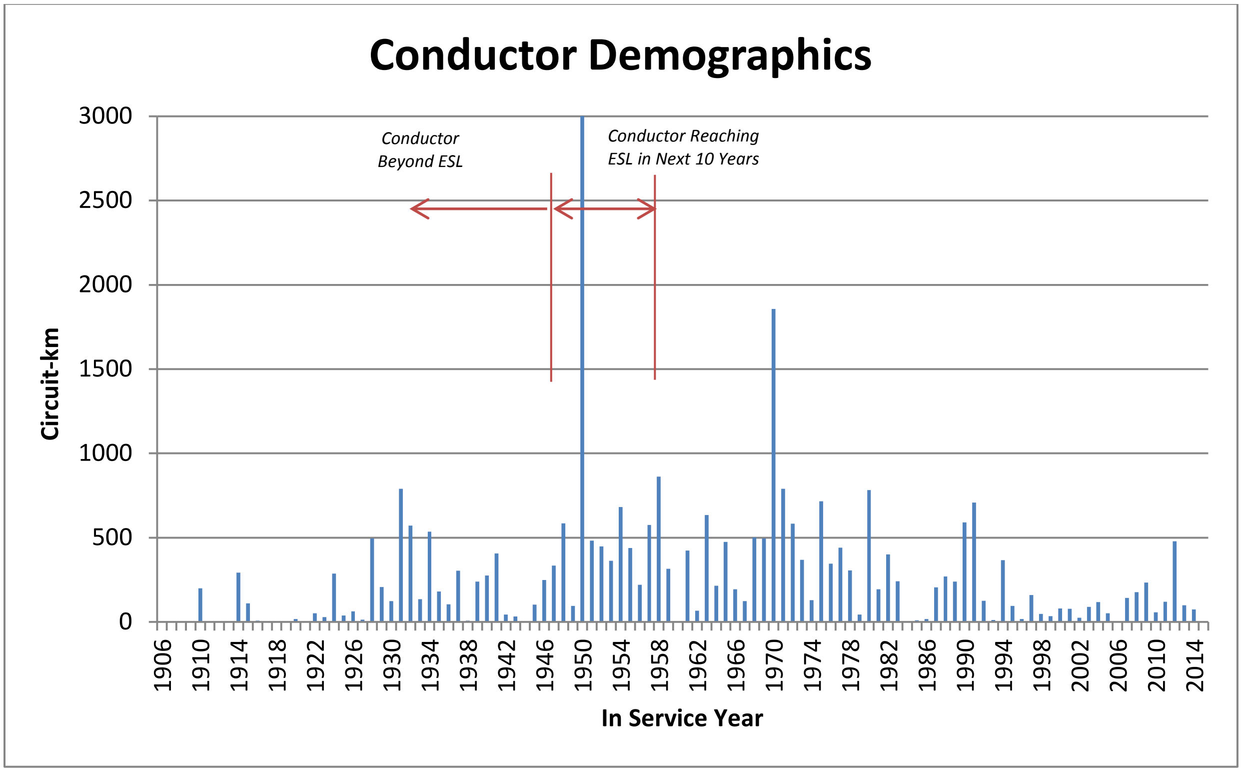


Figure 4: Conductor Demographic Distribution

In addition to the assets currently operating beyond ESL, over the next few years a significant number of assets will also age beyond their ESL. In 10 years 58% of transformers, 40% of breakers and 42% of conductors will be beyond their ESL, unless replaced.

Figure 5 below shows a large group of assets that will be operating beyond their ESL, that may require replacement or refurbishment beginning in 2030. There is a need beginning in 2017 to replace assets currently operating beyond ESL before the next bow wave of sustainment investments arrives in 2030. Increasing the pace of replacements within this window provides an opportunity to manage reliability risk, optimize work execution and smooth the rate impact of sustainment investments.

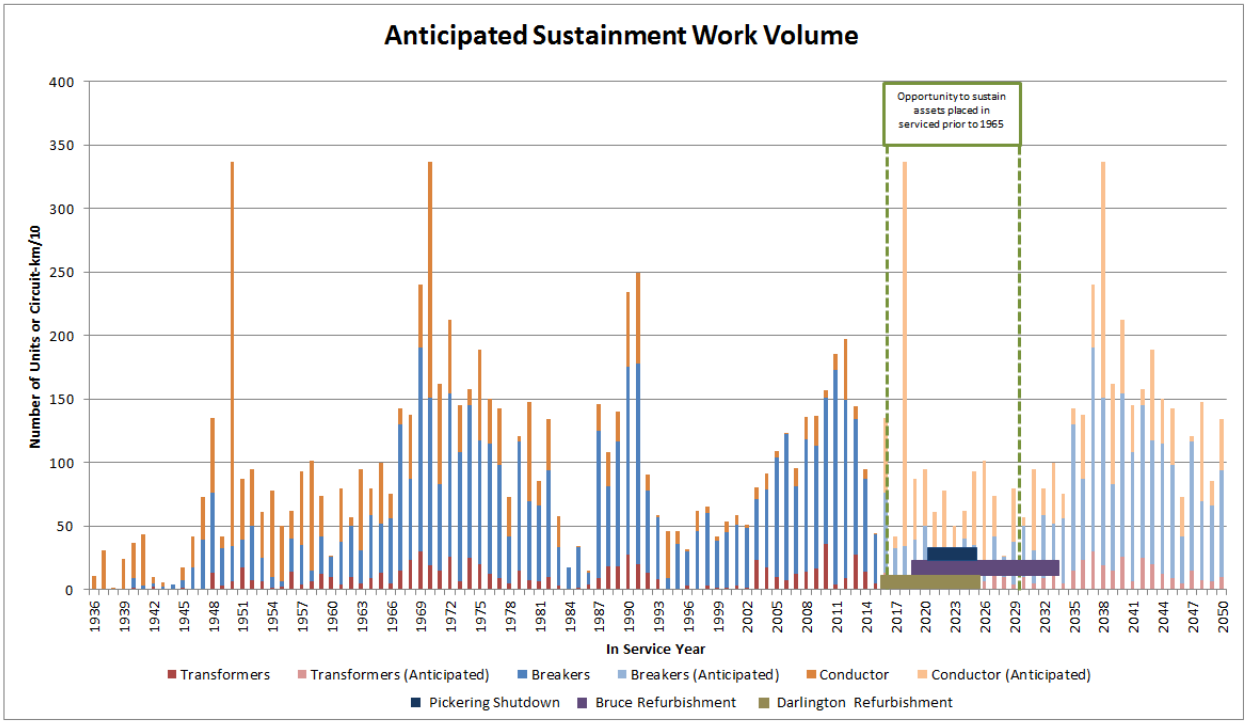


Figure 5: Anticipated Sustainment Work Volume

In addition, Hydro One expects increased outage constraints due to plans to refurbish or retire nuclear generation stations. The nuclear refurbishments at Darlington and Bruce are scheduled to occur between 2016 and 2033, while the planned shut down of the Pickering Generation Station is expected by 2025.

These plans will result in significantly reduced base load generation available between 2022 and 2030. Hydro One's transmission system plan is designed to allow the transmission facilities affecting generation to be in good working order, and thus enable adequate supply of electricity to the IESO-controlled grid during this period.

7. TOTAL COST BENCHMARKING

As a result of the Settlement in its 2015-2016 rate application, Hydro One engaged in a Total Cost Benchmarking study conducted by Navigant Consulting and First Quartile Consulting, that provided a benchmarking study of Hydro One’s transmission costs. In addition to performing the agreed-upon total cost benchmarking study, Navigant was requested by Hydro One to assess best practices and provide recommendations for Hydro One’s consideration. The final report is included in Exhibit B2, Tab 2, Schedule 2, Attachment 1. The Navigant Report provides information about other transmission company investment practices and confirms that the proposed investment levels required to sustain lines and stations is in a range consistent with the experience of other transmission companies.

The Navigant Report supports Hydro One’s investment plan that identifies the need for additional spending to sustain its transmission assets. Hydro One’s capital investment in stations and lines and its OM&A expenditures on these asset types has been notably lower than most of its comparators, and well below the median (Exhibit B2, Tab 2, Schedule 1, Attachment 1). This gap is especially noteworthy considering the age of Hydro One’s towers, circuit breakers and transformers, are among the oldest in the group of comparators (Exhibit B2, Tab 2, Schedule 1, Attachment 4). Navigant noted that "Given the relative age of the Hydro One’s assets, expectation is that CAPEX will need to increase in order to maintain reliability” (Exhibit B2, Tab 2, Schedule 1, Attachment 4).

The Navigant Report was also used as a reference tool to further validate the proposed increases in spending associated with our Transmission System Plan. Based on the results of the report and Hydro One's investment proposal, the 2017 and 2018 total expenses (CapEx and OM&A) will continue to remain at or below median levels relative to Hydro One’s peer set. This finding was consistent whether spending was normalized on fixed asset value or line circuit km.

RELIABILITY RISK MODEL

Hydro One's reliability risk model relies on three key inputs, which are detailed below: asset-specific hazard curves, the asset demographic of Hydro One's current fleet, and the total units of each asset class that are planned to be replaced. The reliability risk model is used to help inform the level of investment required to manage system reliability risk.

1. HAZARD RATES

The Hazard Rate represents the conditional probability of failure, including retirements, in a year given that the asset has survived through the previous years. Each asset class has its own unique hazard rate. Figure 1 shows a typical asset hazard rate for an asset over its lifetime. This hazard curve shows that there is little chance that the facility will fail within the initial years of installation. As the years advance, the hazard rate steadily accelerates. For example at age 50, the hazard rate for a particular asset may be 2.5% and this decays to about 3.2% by age 55 and 6% by age 70.

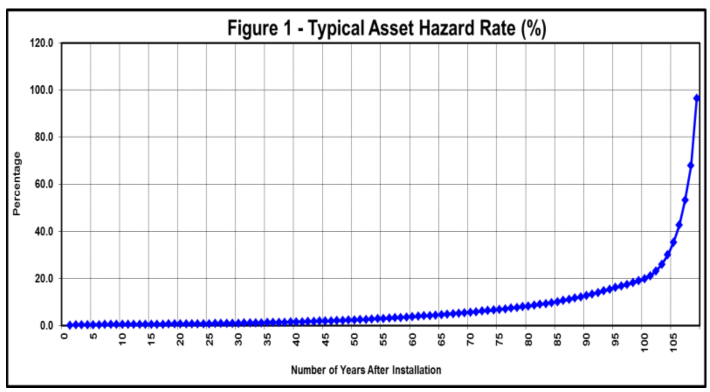


Figure 1 - Typical Asset Hazard Rate (%)

Hydro One's hazard curves were developed based on the results from a report commissioned[1] from Foster Associates entitled, "2014 Asset Failure Analysis." Foster Associates determined the hazard curves for each asset class based on Hydro One’s

[1] *Foster Associates. "2014 Asset Failure Analysis" Report delivered to Hydro One August 19, 2014.*

actual asset demographic data (including vintage and in-service dates) and Hydro One's actual asset failures and retirements caused by asset condition deterioration, performance, wear and tear, actions of the elements, accidents and functional and technical obsolescence.

Foster Associates determined the hazard curves that describe the expected risk profiles for each of Hydro One's major asset groups, including transformers, circuit breakers, and conductors. These curves serve as the basis for estimating asset failure risks in the reliability risk model.

The hazard curves are upward sloping, indicating that as assets age, a higher probability of failure and replacement is to be expected. The essence of mitigating reliability risk is to manage the asset replacements before their failure and before asset reliability performance becomes unacceptable and jeopardizes customer and system reliability.

2. ASSET DEMOGRAPHICS

The hazard curves were applied to Hydro One's asset demographics information, to provide an indication of the probability of failure or deterioration to the point of needing replacement, by asset class. A sample of the asset demographic information for the conductor fleet is shown below:

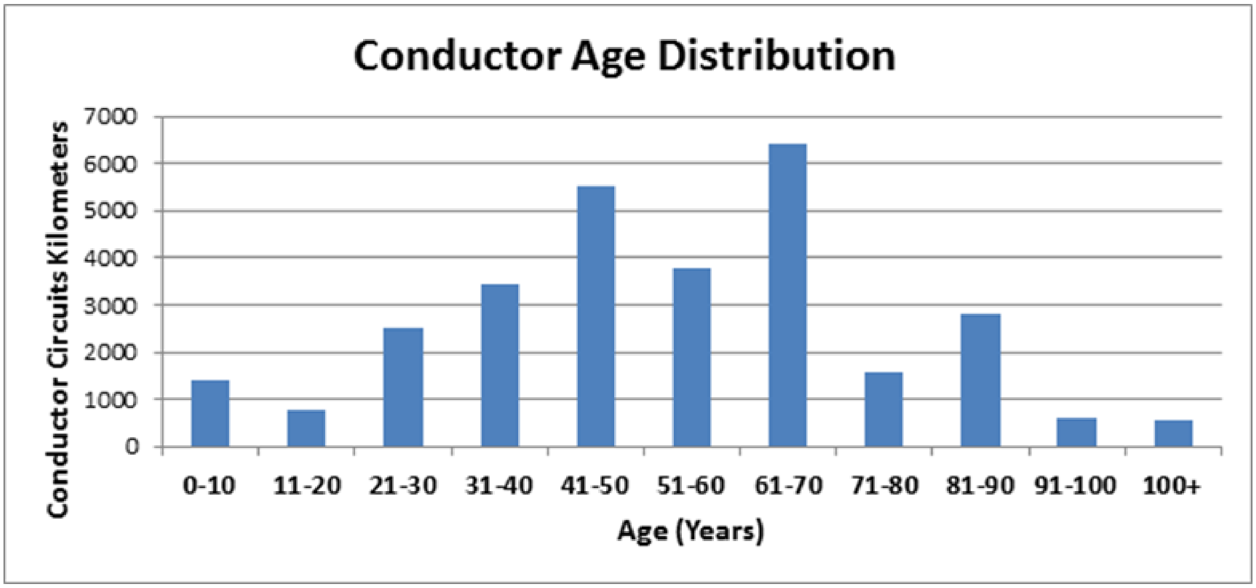


Figure 2: 2016 Conductor Age Distribution

3. PLANNED ASSET REPLACEMENTS

To determine the impact of planned asset replacements over a given time horizon, total units of assets designated for replacements for each asset class were applied to the expected demographics within the study period to determine the future asset demographics. The expected future demographics reflect the planned work and the continued aging of assets over the time period. In a simplified example, if 10 units are selected for replacement, the expected future demographics would reflect that the 10 had been removed and 10 new units introduced, maintaining the same asset totals but with a different demographics profile.

For each of the three most reliability-impactive asset classes, transformers, breakers, and transmission lines, the details of planned work were incorporated into the model assumptions. The model does not take into account new asset additions driven by system development requirements. As new equipment less than 5 years old tends to have zero or close to zero hazard rates, given the low likelihood of failure, the impact of this exclusion is assumed to be minimal.

After the impacts of the planned replacements work had been modeled, the weighted average risk of each asset class was recalculated to develop an expected future risk probability for each asset. For example, in 2017, conductors have a level of reliability risk of 1.06%, and after planned work to replace older lines and continued aging of remaining conductors, the level of risk is expected to fall to 1.03%. The fact that the reliability risk decreases over the time period is driven by the fact that the replacement rate is sufficient to address the continued aging and deterioration of this asset class. To compare the risk relative to today, the expected future risk (1.03%) was divided by the 2017 risk level (1.06%) to obtain a relative risk measure that captures the change in risk in the future compared to present day risk.

4. APPLICATION OF THE RELIABILITY RISK MODEL

The output of the model is a system wide reliability risk measure, which is appropriate as a directional indicator of total system reliability risk to help assess impact of various levels of investment. It does not support individual investment decisions, which are based on an established asset risk assessment process described in Exhibit B1, Tab 2, Schedule 5. This process takes into account each asset’s condition, demographics, equipment performance, criticality, economics and utilization. Other factors such as obsolescence, environmental risks and requirements, compliance obligations, equipment defects, health and safety considerations and customer needs and preferences are also considered.

This model yields an optimistic reliability risk directional indicator. It relies on hazard curves, which were derived from Hydro One asset removal history. Hydro One manages one of the oldest transmission asset fleets in the industry, with recent benchmarking suggesting that Hydro One had one of the oldest breaker and transformer fleets among its peers in the US and Canada.[2] Hydro One continues to maintain and operate many asset classes beyond their expected service life at the expense of increased operating cost and increased reliability risk. Therefore, the model is appropriate as a directional indication, amongst other considerations, to help inform an appropriate level of investments.

[2] Navigant /First Quartile Total Cost Benchmarking study, p.5.

5. SUMMARY OF RISK MODEL ASSUMPTIONS

Asset	**Critical Inputs and Assumptions**		
	Demographics	**Hazard Curves**	**Units of activity under investment plan**
Transformers	Hydro One's transformer demographics as of Jan. 2016	• Hazard curves for each type of transformer (e.g. auto-transformer, step down transformer) were applied to the asset demographics of that type of transformer; calculated a weighted average to arrive at an asset-class level metric	• Oldest transformers were assumed to be prioritized for replacement according to proportion of total transformers beyond expected service life for each transformer type
Circuit Breakers	Hydro One's breaker demographics as of Jan. 2016	• Hazard curves for each type of circuit breaker (by both voltage and type of equipment) were applied to the asset demographics of that type of breaker; calculated a weighted average to arrive at an asset-class level risk metric • SF6 Breakers were modeled with a shape factor determined by an expected average age of 40 years based on the expected longevity of newer SF6 breakers compared to older SF6 breakers which experienced shorter asset lives	• Higher-voltage (230 and 500KV) air blast circuit breakers prioritized for replacement due to reliability performance and obsolescence • HV and SF6 oil breakers prioritized for replacement after air blast replacements • Lower-voltage air blast circuit breakers prioritized for replacement after HV replacements • Low voltage oil breakers prioritized after air-blast for replacement • Assumed removed air-blast and oil breakers replaced with new SF6 breakers consistent with Hydro One's asset plans
Conductors	All asset demographics in circuit kilometers Conductor asset demographics as of Jan 2016	• Hydro One's lines demographics extended beyond the age (90) at which the hazard curve for conductors reached a limit of 4.6%. • Assumption built into model of 1% increase in risk for every year of aging past 90 in order to more realistically represent the risk facing aging conductors	• Oldest conductors assumed to be replaced first

IDENTIFYING ASSET NEEDS:
ASSET-SPECIFIC ASSESSMENTS

1. INTRODUCTION

This Exhibit describes how Hydro One determines its assets' needs, primarily focusing on Sustainment capital spending.

2. SUSTAINMENT NEEDS

Consistent with the asset management strategy described in Exhibit B1, Tab 2, Schedule 4, individual asset needs are determined using an asset risk assessment ("ARA") process, which relies on asset condition data, engineering analysis, and other information, including the input of experienced planning professionals. Exhibit B1, Tab 2, Schedule 6 contains a comprehensive overview of the condition of Hydro One's transmission assets and their needs, which supports proposed capital spending.

2.1 Asset Risk Assessment Methodology

The ARA methodology is an evolution of the asset condition assessment approach described in previous transmission rate filings (EB-2012-0031[1], EB-2010-0002[2]), extending the definition of asset risk to encompass risk factors other than asset condition.

[1] EB-2012-0031, Exhibit A, Tab 13, Schedule 2 "Transmission 10 Year Outlook".
[2] EB-2010-0002, Exhibit A, Tab 12, Schedule 4 "Investment Plan Development".

As illustrated in Figure 1, in the ARA methodology, different sources of risk are considered in developing a multi-faceted picture of asset risk.

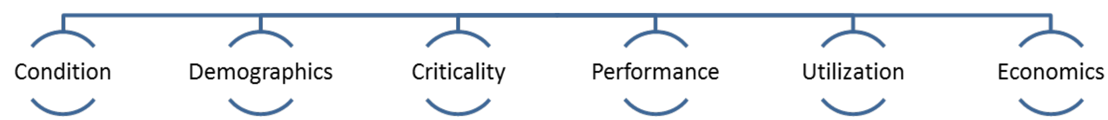


Figure 1: Factors used to evaluate asset risk

In assessing asset needs, planners also consider other factors such as environmental risks and requirements, compliance obligations, equipment defects, health and safety considerations and customer needs and preferences. Planners then make recommendations regarding what investments should be made within an identified timeframe. To clarify, the ARA is one step in the asset planning process; it does not replace decisions made by qualified engineers in conjunction with physical inspections.

2.1.1 Asset Condition Risk

Asset condition risk relates to the increased probability of failure that assets experience when their condition degrades over time, which is based on empirical data. Asset condition is defined using different criteria, depending on the asset. For example, the condition of a transmission station transformer is measured by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test, and if required, a boring test. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently. Assets of a given type that have a relatively high condition risk are candidates for refurbishment or replacement.

2.1.2 Asset Demographic Risk

Asset demographic risk relates to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage, which is based on empirical data. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages. Assets with relatively high demographic risk are candidates for refurbishment or replacement.

2.1.3 Asset Criticality

Asset criticality represents the impact that the failure of a specific asset would have on the transmission system. Primarily, it is used to show relative importance of an asset compared to other assets of the same type. Assets whose failure would result in an interruption to a larger amount of load would have an asset criticality that is higher than assets whose failure would have a smaller impact on the system load. Asset criticality is used to prioritize the refurbishment or replacement of assets whose condition, demographic, performance, utilization or economic risk has already resulted in the asset being considered a candidate for refurbishment or replacement.

2.1.4 Asset Performance Risk

Asset performance risk reflects the historical performance of an asset, which is based on empirical data. Performance is defined by any power interruptions that have been caused by failure of the asset. This risk factor considers the frequency and duration of these interruptions, as well as whether the interruptions are occurring more or less frequently over time. Past performance can be a good indicator of expected future performance.

Therefore, assets with a relatively high performance risk can be considered candidates for refurbishment or replacement.

2.1.5 Asset Utilization Risk

Asset utilization risk represents the increased rate of deterioration exhibited by an asset that is highly utilized, which is based on empirical data. The relative deterioration of some assets is highly dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded relative to their nameplate rating deteriorate more quickly than those that are lightly loaded. Similarly, circuit breakers utilized for capacitor and reactor switching which are subject to significant operations experience accelerated mechanical and electrical wear-out of the breaker. Therefore, the asset utilization risk for transformers and circuit breakers attempts to consider their relative deterioration based on available loading and operation history, respectively.

Assets that exhibit a high utilization risk compared to other assets of the same type are considered candidates for upgrade, especially if they also carry a relatively high asset criticality or are deemed candidates for refurbishment or replacement based on other risk factors.

2.1.6 Asset Economic Risk

Asset economic risk is based on the economic evaluation of the ongoing costs associated with the operation of an asset. Depending on the asset type, this evaluation may be as simple as determining the replacement cost of the asset, or as complex as comparing the present value of ongoing maintenance to that of complete refurbishment or replacement.

While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement.

2.2 ARA Data

Asset condition data is collected during routine maintenance, inspections and testing. For each specific asset, information on condition, performance history, utilization, criticality and other non-condition characteristics is compiled into a database for planning purposes. Improving the quality and quantity of this data is an ongoing objective for Hydro One.

3. DEVELOPMENT, OPERATIONS, AND COMMON CORPORATE NEEDS

Development activities focus on customer-specific and system-level needs, which are discussed in Exhibit B1, Tab 2, Schedules 2 and 3. In Operations, asset needs are driven by the lifecycle of facilities and tools, which are primarily information technology ("IT") tools, as well as compliance requirements. Other determinants include the requirement to facilitate renewable generation and conservation initiatives.

Common Corporate asset needs are determined by organizational and compliance requirements. Fleet, real estate and facilities requirements are assessed annually between the relevant organizations within the company. There are compliance requirements that drive asset needs for fleet, real estate and facilities, but the primary determinants are the support requirements of the Sustainment, Development, and Operations workstreams. IT needs are driven by corporate requirements and compliance requirements, such as the NERC Critical Infrastructure Protection Standards.

Witness: Chong Kiat Ng

IDENTIFYING ASSET NEEDS: ASSET NEEDS OVERVIEW

1. INTRODUCTION

The information presented below is an overview of asset condition for key transmission assets. These summaries provide an overview of the criteria used to assess the fleet of assets, including factors such as demographics, condition assessment, performance, and other relevant factors that lead to asset replacement decision as described in Exhibit B1, Tab 2, Schedule 4 and further explained in Exhibit B1, Tab 2, Schedule 5.

Decisions to replace assets are based on achieving the business objectives, (found in Exhibit B1, Tab 1, Schedule 2), including: mitigating reliability risk, maintaining first quartile reliability in a safe manner, and responding to the needs and preferences of Hydro One's customers. Decisions are also made to ensure compliance with regulatory, environmental and reliability standards. Employee safety concerns are also considered in the decision making process as Hydro One drives towards an injury free workplace. Where feasible, asset life is extended to defer larger capital replacement through maintenance programs.

2. TRANSMISSION STATION ASSETS

2.1 Transformers

2.1.1 Asset Overview

Transformers are a major component of the transmission system that performs voltage transformation functions to connect the transmission grid to load centers. Energy is lost in the process of transmitting electricity over long distances. Transformers are used to step up the voltage to transmit electricity over long distances and to step down the voltage at the customer's delivery point, to limit losses and the overall cost of the transmission system.

Hydro One has 721 large transmission class transformers in service, as outlined in Table 1.

Table 1: Transformer by Type

Transformer Type	***Number of Transformers***
Autotransformer – 500 kV	40
– 345 kV	4
– 230 kV	87
230 kV Phase Shifter / 230 kV Regulator / 500 kV Reactor	9
Step Down Transformer – 500 kV	1
– 230 kV	292
– 115 kV	288

The most common power transformer is the step-down transformer, which converts a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Another type is the autotransformer (as depicted in Figure 1) which connects to high voltage transmission systems such as 500/230 kV and 230/115 kV. Other transformers included in this group are phase shifting transformers, shunt reactors, and regulating transformers.

Figure 1: 500/230 kV Autotransformer

- Currently 28% of the transformer population is beyond its expected service life.
- The condition of the transformer fleet, determined through industry standard diagnostic testing, is such that 15% present high or very high condition risks that need to be mitigated.
- The forced outage frequency of transformers has been relatively stable over the last decade. However, transformer failures can have a significant impact to local and system reliability. Transformers failures also have a negative impact on the environment in the event of oil spills.

Given the demographics of the transformer population, the condition trend and the risks associated with transformer failures including reliability impact, environmental and safety concerns, Hydro One plans to replace 27 transformers in 2017 and 22 in 2018. Regulatory requirements related to oil leaks, noise levels and PCB contaminated oil in equipment also contribute to the need to replace some of the transformer fleet.

2.1.2 Asset Strategy

Hydro One’s strategy for transformers is to manage the fleet in a manner that preserves reliability and minimizes life cycle cost. OM&A expense is limited through the use of reliability centered maintenance that is necessary to maintain the assets as needed to continue their safe and reliable operation. Transformers whose condition has deteriorated to the extent affecting their safe, reliable and efficient operation will be replaced. In addition, transformers needing replacement due to other factors are as described in Exhibit B1, Tab 2, Schedule 4. This will result in approximately 3.4% of transformers being replaced in each of the test years.

2.1.3 Asset Assessment Details

Demographics

Hydro One uses a normal expected service life (Expected Service Life or "ESL" defined as the average time in years that an asset can be expected to operate under normal system conditions) of between 40 years and 60 years depending on the type of transformer. Table 2 outlines the ESL for various types of transformers.

Table 2: Transformer Expected Service Life

Transformer Type	***Expected Service Life***
Autotransformer – 500 kV	40 years
– 230 kV	50 years
Phase Shifter / Regulator / Reactor	40 years
Stepdown Transformer – 230 kV two-winding	50 years
– 115 kV or 230 kV three-winding	40 years
– 115 kV two-winding	60 years

The average age of the transformer fleet is currently 34 years of age and 28% of the in-service transformers are currently beyond their expected service life. The demographics of the transformer population are outlined in Figure 2.

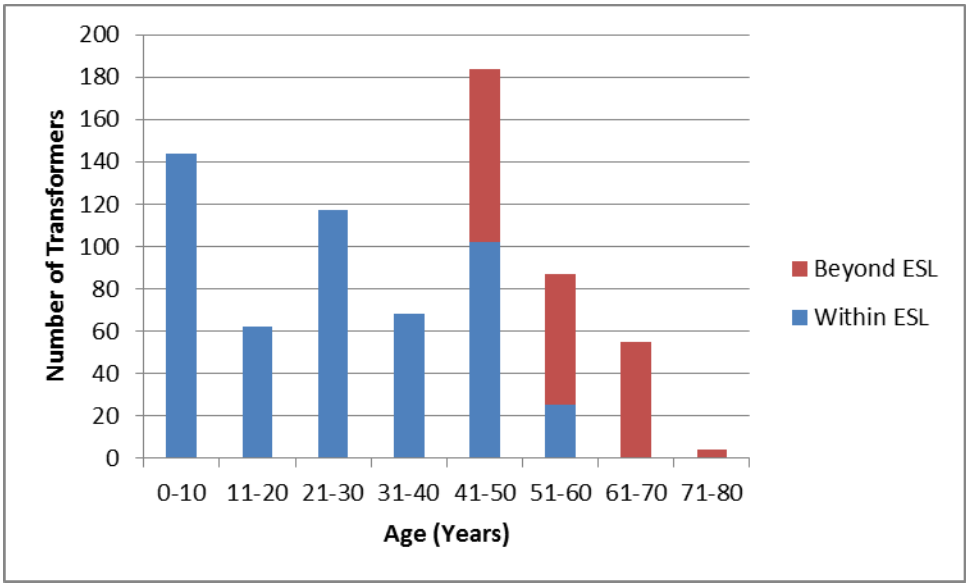


Figure 2: Demographics of the Transformer Fleet

The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through continued capital replacement programs.

<u>Performance</u>

The forced outage frequency and duration of transformers are relatively stable, as demonstrated in Figures 3 and 4. However, transformers failures can have a significant impact to local and system reliability and current reliability performance is not a sufficient indicator of asset needs.

Transformer forced outages are one of the leading causes of customer delivery point interruptions, and represent 18% of the equipment caused events impacting delivery point interruptions with multiple supplies over the past 10 years. To mitigate this risk, the proposed transformer replacements in the test years are focused on replacing transformers that may lead to delivery point interruptions and impacting system reliability, customer satisfaction and other adverse outcomes. This is determined through the Asset Risk Assessment process outlined in Exhibit B1, Tab 2, Schedule 5.

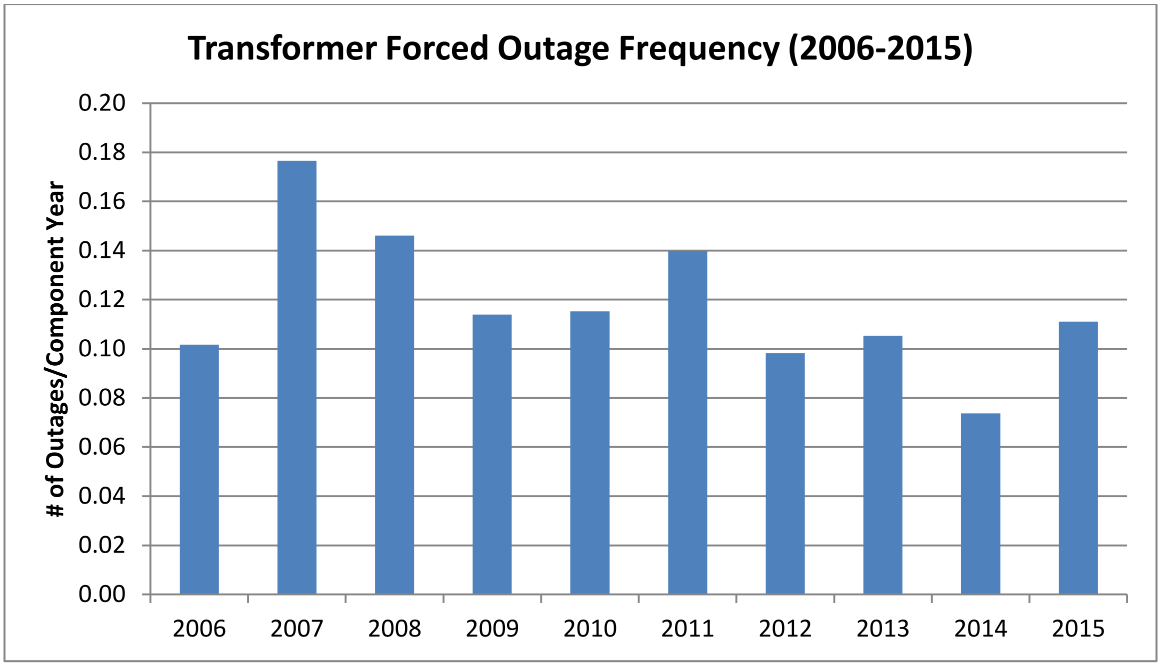


Figure 3: Forced Outage Frequency of Transformers

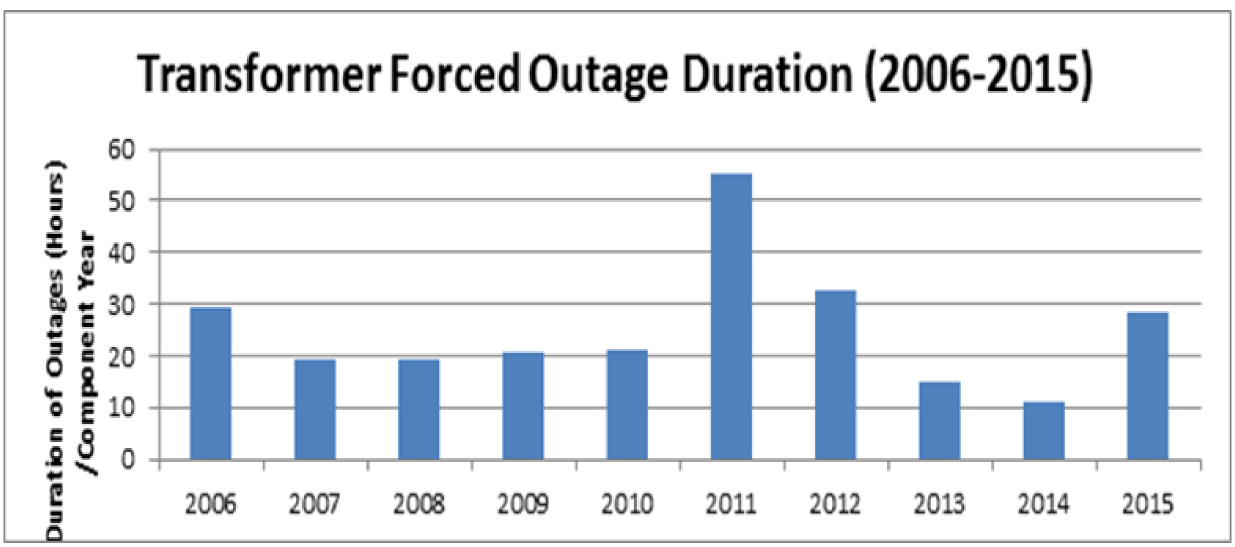


Figure 4: Forced Outage Duration of Transformers

<u>Condition</u>

Transformer condition is a leading predictive indicator of equipment reliability. Condition is primarily based on transformer oil testing (dissolved gas analysis, furan, standard oil testing), power factor testing, and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, heat from transformer loading, exposure to oxygen, moisture contamination, and damaging acids in the insulating oil as a result of insulation aging. Degradation is irreversible and transformer replacement is the only viable solution.

Based on the latest analysis, 15% of Hydro One's transformer population is rated high or very high risk, as outlined in Figure 5.

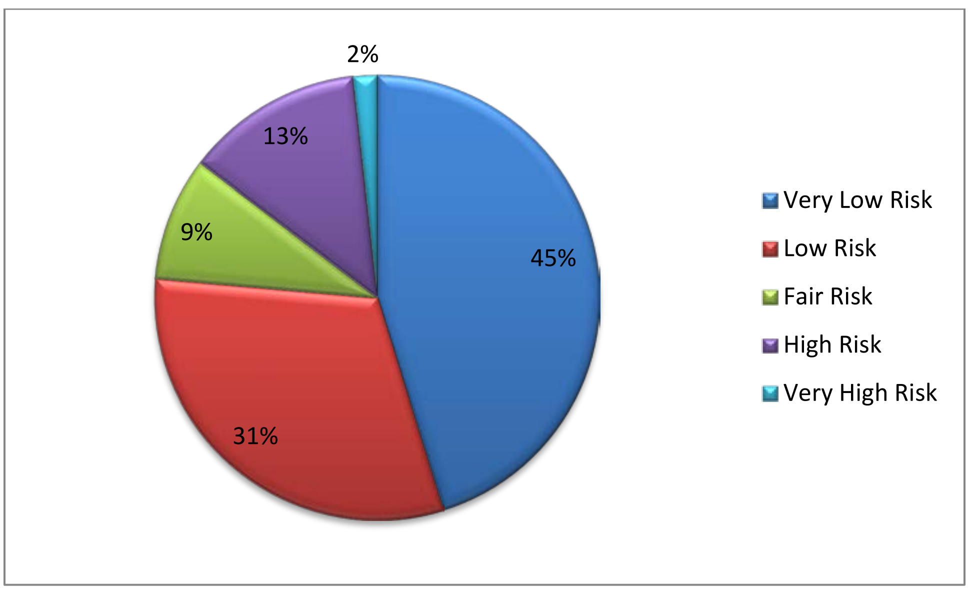


Figure 5: Transformer Fleet Condition Assessment

To date, the sustaining replacements have addressed many of the transformers with the highest probability of failure, along with a number of maintenance activities that have focused on remedial actions to mitigate the most significant risks. This has stabilized overall condition of the asset fleet.

Other Influencing Factors

Other factors considered when determining the need for transformer replacement include:

- Oil Leaks - Provincial regulations require that oil leaks are mitigated either through temporary measures such as absorbent materials and drip trays, through typically expensive refurbishment to re-gasket transformers, or replacement. Replacement is often the best technical and economical solution for transformers with these problems.

- Environmental Compliance Approval ("ECA") Commitments - formerly Conditions of Approval, or "CofA". Often ECA approvals include conditions requiring transmission station equipment to meet modern environmental standards within a specified period of time, typically 3 years. Transformers are usually the influencing factor in ECA commitments for both spill containment and noise limits.
- Safety - Power transformers can experience catastrophic explosions and fire if their condition is deteriorated. Power transformer outages can represent a concern for employee and public safety as individuals may be exposed to unneeded risks and harmed from the results of transformer failure as well as through prolonged power outages.
- Standardization – Replacement and upgrades of older transformers allows the equipment fleet to better achieve standardized configurations that meet up to date standards, which in turn mitigate safety and environmental risks. Modern transformers are more efficient with lower electrical losses.
- System Evolution – Load growth and renewable generation connections may lead to an increase in capacity requirement that is beyond the functional capability of existing transformers.

Table 3 below provides the historic replacement rate of transformers.

Table 3: Transformer Replacement Rate

Transformer Portfolio	Historic			Bridge	Test	
	2013	2014	2015	2016	2017	2018
# of Replacements	15	24	21	19	27	22
% of Fleet	2.1%	3.3%	2.9%	2.6%	3.7%	3.1%

The capital replacement rate in the test years is needed to manage reliability and reliability risk through the test years. Transformers are a major element in ensuring a reliable bulk electricity system. Transformer failures directly affect load customers, either through loss of load or increased risk resulting from the loss of system redundancy, until such time the transformer can be replaced. Maintaining the fleet in an adequate condition preserves reliability consistent with good utility practice and regulatory obligations.

2.2 Circuit Breakers

2.2.1 Asset Overview

Hydro One has 4,543 circuit breakers in service, as outlined in Table 4. High voltage ("HV") breakers are installed in 500 kV, 230 kV or 115 kV positions, and medium voltage ("MV") breakers are installed at 44 kV, 27.6 kV, 13.8 kV or 12.5 kV positions.

Table 4: Circuit Breakers by Type

Circuit Breaker Type	*Number of Circuit Breakers*		
	HV	*MV*	*Total*
Oil	420	1297	1717
SF6	643	1006	1649
Air Blast	167	5	172
GIS	122	40	162
Metalclad	0	815	815
Vacuum	0	28	28

A circuit breaker is a mechanical switching device that is capable of making, carrying and interrupting electrical current under normal and abnormal circuit conditions. Abnormal conditions occur during a short circuit such as a lightning strike or conductor contact to ground. During these conditions, very high electrical currents are generated that greatly exceed the normal operating levels. A circuit breaker is used to break the electrical circuit and interrupt the current to minimize the effect of the high currents on the rest of the system. Figures 6A through 6E illustrate the five primary types of circuit breakers used in Hydro One's transmission system.

Figure 6A: Oil Circuit Breaker

Figure 6B: SF6 Circuit Breaker

Figure 6C: Metalclad Circuit Breakers

Figure 6D: Air Blast Circuit Breakers

Figure 6E: 500kV GIS Circuit Breakers

- Currently 9% of the circuit breaker population is beyond its expected service life.
- The condition of the circuit breaker fleet, determined through industry standard maintenance practices, is such that 11% present high or very high condition risks that need to be mitigated.
- Over the past three years the forced outage frequency of circuit breakers has been higher than historically, primarily due to Air Blast Circuit Breakers (ABCB) performance. Circuit breaker failures can have a significant impact to local and system reliability and continue to be one of the leading causes of delivery point

interruptions. Circuit breaker failures also have a negative impact on the environment in the event of SF6 gas release.

Given the demographics of the circuit breaker population, the condition and the risk associated with circuit breaker failures, an increased rate of replacement over historic years is required to maintain system reliability performance.

2.2.2 Asset Strategy

Hydro One's strategy for circuit breakers is to accelerate replacement of poor performing circuit breakers to maintain system reliability. A targeted approach will focus on replacement of worst performing and/or obsolete breaker types, primarily the air blast circuit breakers. Hydro One is also shifting towards increasing the number of circuit breaker replacements completed in an integrated capital investment manner. At select stations, entire low voltage switchyards will be replaced with pre-fabricated solutions consisting of metalclad or gas insulated switchgear (GIS), which are beneficial in areas of construction, maintenance, and reliability. This equipment has a smaller footprint than an air insulated station and the current carrying components are protected from sources of foreign interference such as animals and weather which could cause outages.

2.2.3 Asset Assessment Details

<u>Demographics</u>

Hydro One uses an expected service life ("ESL") of 40 years for all circuit breakers with the exception of oil circuit breakers, where an ESL of 55 years is used.

The average age of the circuit breaker fleet is currently 28 years of age and 9% of the in-service circuit breakers are currently beyond their expected service life. The demographics of the population are outlined in Figure 7.

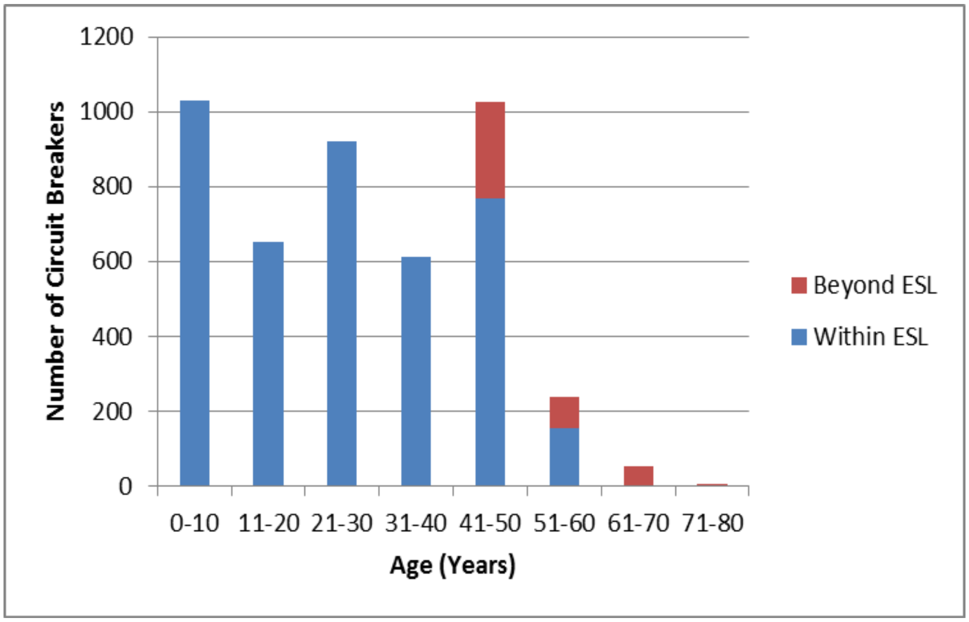


Figure 7: Demographics of the Circuit Breaker Fleet

Historic replacements have been generally sufficient to maintain a relatively small portion of the overall circuit breakers in operation beyond their ESL. Within the overall population, there are certain circuit breaker types which are operating at or beyond their ESLs.

- Approximately 80% of the high voltage air blast circuit breakers are beyond their ESL. These breakers are typically installed at system critical network stations;
- A large portion of the aged inventory is oil circuit breakers. Replacement is focused on only the worst performing and/or technically obsolete models.
- A significant portion of the metalclad breakers are operating well beyond their expected life. Legacy designs come with inherent safety risks that require mitigation.

Continued renewal of the fleet will be required to manage risks to system and customer reliability as a result of the long-term demographic pressures, as well as the more acute issues associated with air blast and metalclad circuit breakers.

<u>Performance</u>

As displayed in Figures 8 and 9, the number of forced outages due to circuit breakers and the duration of those outages both increased beginning in 2013. This was primarily the result of increased outages among the Air Blast Circuit Breakers (ABCB) compared to previous years.

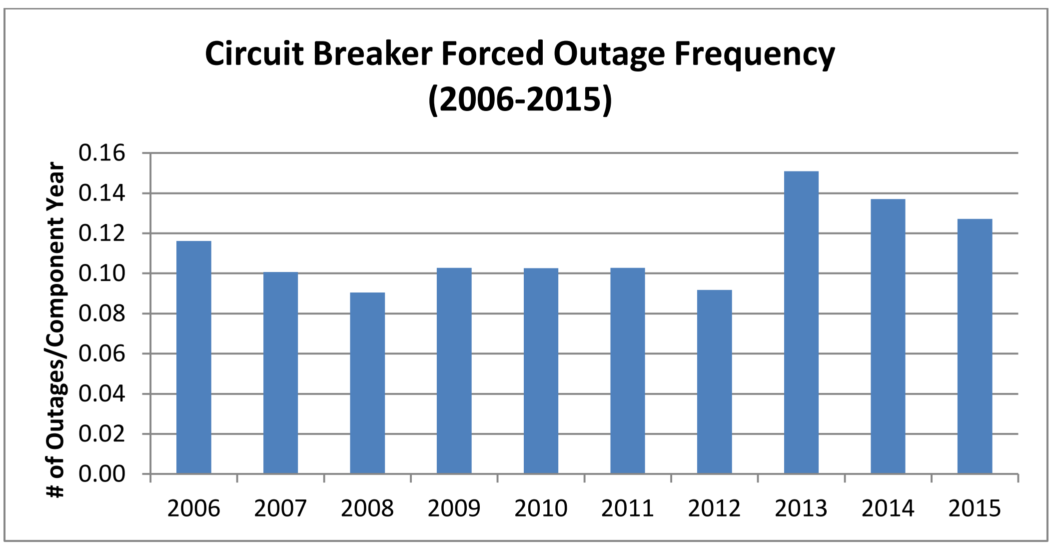


Figure 8: Forced Outages Frequency of Circuit Breakers

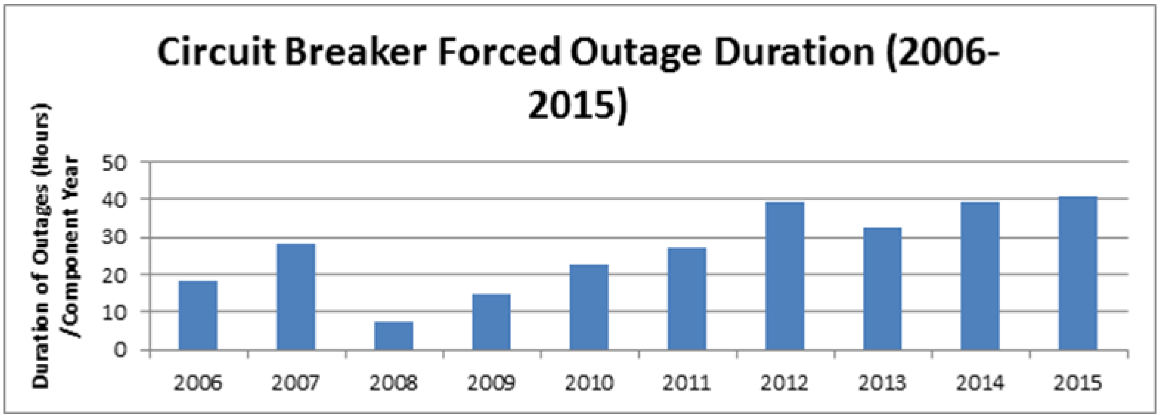


Figure 9: Forced Outage Duration Caused by Circuit Breakers

In 2014 and 2015 the number of outages has been declining modestly from 2013 as ABCBs have been replaced throughout the system. This trend is notable in Figure 10, where the performance data for the different breakers in Hydro One system is depicted. Oil and SF6 breakers have steady trend whereas ABCBs have a significant increase.

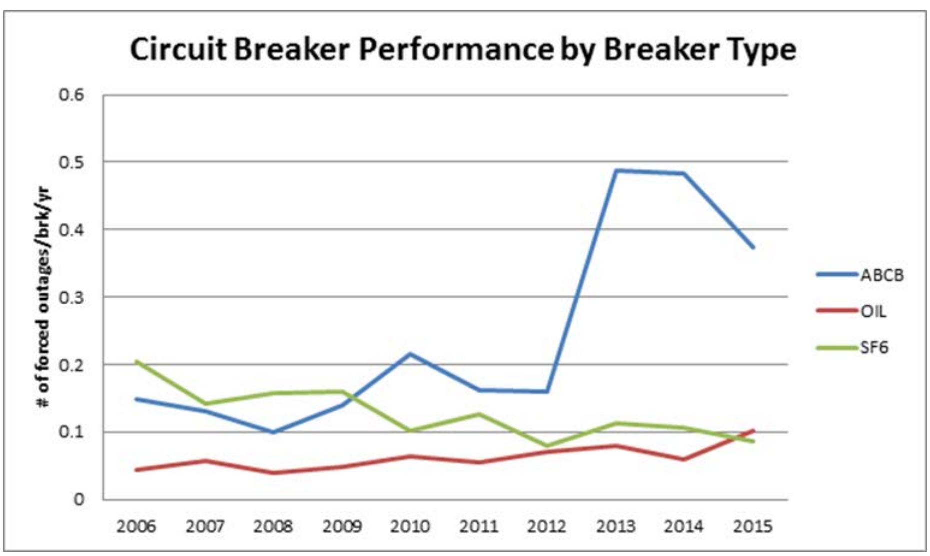


Figure 10: Forced Outage Frequency of Circuit Breaker by Type

Condition

Circuit breaker condition is primarily based on assessment from preventive maintenance and corrective maintenance programs through diagnostic testing such as breaker timing, breaker oil analysis, history of deficiencies, and other tests. The components generally degrade over time based on the amount of usage. In some cases the degradation can be addressed through replacement of worn components during maintenance, but in many cases replacement of the circuit breaker is the only viable solution.

Currently 11% of Hydro One's circuit breakers rated high or very high risk based on asset condition, as outlined in Figure 11.

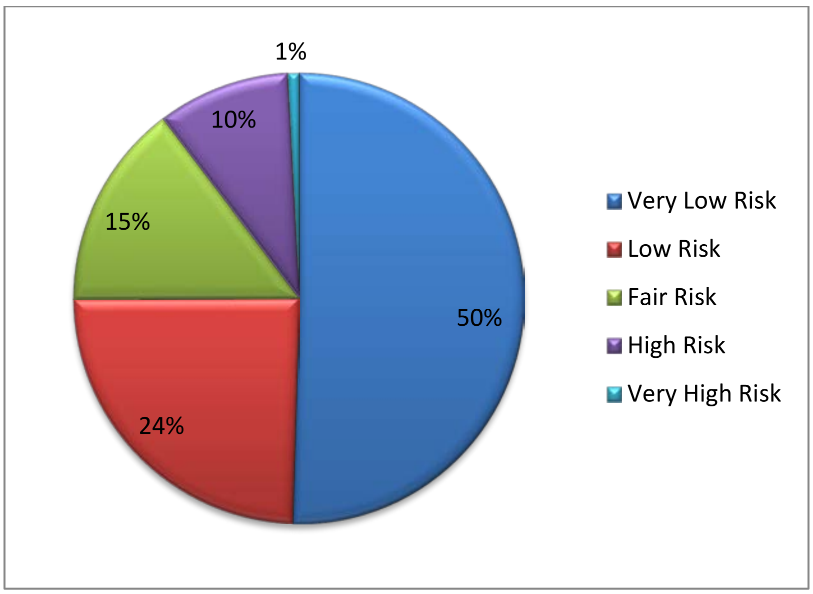


Figure 11: Circuit Breaker Fleet Condition Assessment

<u>Other Influencing Factors</u>

Other factors considered when determining the need for circuit breaker replacement include:

- Safety - As the circuit breaker design has evolved over the past 50+ years, so have safety standards and the requirement for safer work methods to protect utility workers. Early generation metalclad switchgear is most notable for having significant arc flash and electrical burn hazards in the event of equipment failure. These risks become more significant as the equipment ages.

- Technical Obsolescence - Many breakers are no longer supported by vendors and aftermarket parts are not available or cost effective. This is a significant factor for air blast circuit breakers, some first generation SF6 circuit breakers, and certain types of metalclad and oil circuit breakers.
- Equipment Operations - Breakers that have exceeded their expected service life in terms of number of operations, have parts that are significantly worn, and are considered for replacement. Due to their frequent operation, this is most typical of capacitor and reactor breaker positions.
- Environmental Impact – Minimizing SF6 emissions and their resultant impact as a greenhouse gas to the environment is considered in the replacement or refurbishment plans for SF6 breakers.
- System Evolution – Load growth and renewable generation connections may lead to increase in short-circuit requirement that is beyond the functional capability of existing breakers.

Table 5: Circuit Breaker Replacement Rate

Circuit Breaker Portfolio	Historic			Bridge	Test	
	2013	2014	2015	2016	2017	2018
# of Replacements	57	83	31	43	66	132
% of Fleet	1.2%	1.8%	0.7%	0.9%	1.5%	2.9%

The capital replacement rate in the test years is an increase over historic and bridge levels. Continued renewal of the fleet at an increased rate is required to maintain system reliability performance through the test years.

Circuit breakers are a major element in ensuring a reliable bulk electricity system. Breaker failures are directly impactive to load customers, either through loss of load or significant risk exposure of single supply until such time the station configuration can be returned to normal. Maintaining the fleet in an adequate condition will help preserve reliability and is aligned with good utility practice and regulatory obligations.

2.3 Protection and Automation

Protection and automation assets are utilized to protect, control and operate the transmission system by sensing and isolating abnormal system conditions, providing real-time operational data and remote equipment control, and capturing detailed records for post-event analysis. Automation includes the systems for control, monitoring, and cyber security which are critical activities for the system.

<u>Protection</u>

Protective relays and their associated systems are critical elements of the transmission system. They are connected throughout the transmission network to detect abnormal system conditions caused by natural events, physical accidents, or equipment failure. Upon detecting an abnormal condition, the protection systems immediately operate the necessary station equipment, such as circuit breakers and switches, to isolate faulted components from the rest of the electrical network allowing the power system continue operate. Both failure to operate and incorrect operation of protection equipment can result in major system upsets involving increased equipment damage, increased personnel hazards, and possible long interruption of service.

<u>Control and Monitoring</u>

Control and monitoring are critical to the operation of the Ontario power grid. Hydro One must be able to control and monitor the power system assets and facilities that are deemed important to the safe, reliable and efficient operation of its transmission systems. The ability to control and monitor these assets and facilities enables system operators to respond immediately to an emerging problem, to assess system conditions in real-time and to manage planned work on the system.

Cyber Security

The North American Electric Reliability Corporation (NERC) is a not-for-profit international authority whose mission is to ensure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Figure 12: Regional Electric Reliability Councils under NERC Authority

NERC is committed to protecting the bulk power system against cyber security compromises that could lead to equipment mis-operation or system instability. On November 22, 2013, FERC approved Version 5 of the critical infrastructure protection cyber security standards (CIP Version 5), which represent significant progress in mitigating cyber risks to the bulk power system.

Under the IESO's Market Rules Hydro One is required to comply with all applicable NERC and NPCC standards, including NERC Critical Infrastructure Protection ("CIP") standards which set the requirements for physical and cyber security of critical assets within stations.

The cyber security program includes the implementation of systems and facilities required to achieve and sustain compliance with the NERC Critical Infrastructure Protection standards and address other cyber security vulnerabilities of equal or greater risk.

As outlined in proceeding EB-2012-0031, the energy sector is categorized as critical infrastructure. This classification initiated the development of a set of ten NERC Critical Infrastructure Protection standards (CIP-002 to CIP-011), also referred to as the "Cyber Security" standards, the purpose of which is to protect the reliability of the interconnected grid. In addition, NPCC Directory 4 instituted specific requirements for ensuring cyber security of grid protection systems. Hydro One must maintain compliance with the requirements of these standards. In addition, Hydro One follows good utility and IT Security practice to ensure that all cyber vulnerabilities are identified and secured.

2.3.1 Asset Overview

Hydro One currently has over 12,100 protection systems in service. They comprise three technological vintages; electromechanical, solid state, and microprocessor, as outlined in Table 6.

Table 6: Protection Systems by Technology

Protection System Technology	*Number of Protection Systems*
Electromechanical	4318
Solid State	2409
Microprocessor	5376

By population, electromechanical and microprocessor protections are the most prevalent in Hydro One's fleet. Electromechanical relaying utilizes the principles of electromagnetic induction to convert electrical energy to mechanical movement to detect faults. In contrast, solid state systems rely on transistors using integrated circuit technology to detect fault conditions and microprocessor based systems provide advanced monitoring and fault detection capabilities. Figures 13A through 13C illustrate the three technology types of protection systems used in Hydro One's transmission system.

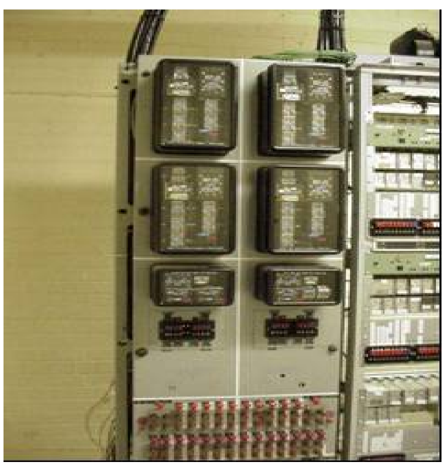


Figure 13A: Electromechanical Relay Panel

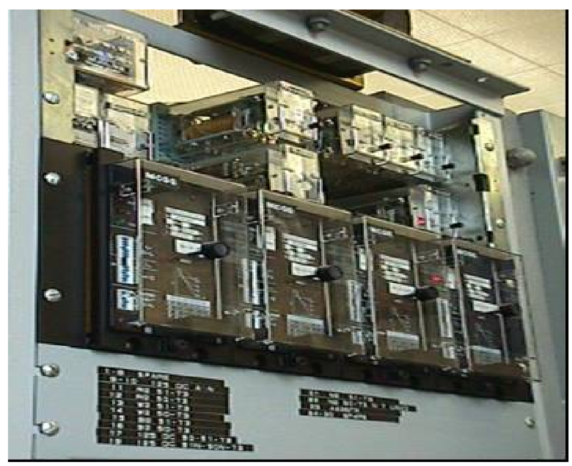


Figure 13B: Solid State Relay Panel

Figure 13C: Microprocessor Based Protection Scheme

New microprocessor based protection systems are also known as Intelligent Electronic Device (IED). IEDs provide multiple protection functions all within a single unit (smaller footprint) and offer features such as capability to provide measurements such as telemetry, event recordings, oscillography, and faults location, all within a single unit. This enables technical analyses of power system faults and relay performances.

- Currently 21% of the protection system population is beyond its expected service life. The existing replacement rate of approximately 450 units per year is required to maintain this level.
- The condition of the protection system fleet is such that 27% present high or very high condition risks that need to be mitigated. There are specific concerns with Programmable Auxiliary Logic Controller (“PALC”) relays, a solid state system, that have experienced an increase in defects over the last 10 years.
- Protection systems are composed of up to 100 individual components. With the vast number of protections, and complexity of replacement, there is risk that a common mode of failure for common manufacturer types/designs may be experienced.

Planned outages may be disrupted and provincial (or interconnected system) reliability may be eroded when protection systems are out of service.

Given the demographics of the protection system population, the condition trend and risks associated with protection failures, continuous focus on replacement effort is required to maintain system reliability performance.

2.3.2 Asset Strategy

Hydro One's strategy for protection systems is to manage electromechanical, solid state and microprocessor relays' obsolescence through timely replacement, and to maintain reliability, dependability, and security of the protection systems. Standardization of protection systems improve productivity as it reduces training costs, maintenance cost and improves the safety of field staff, as each protection assembly is designed with the standard equipment isolation features.

Hydro One continues to contain OM&A expenditures through the replacement of electromechanical and solid state relays with microprocessor based systems which require less frequent maintenance while providing enhanced monitoring to ensure reliability. A replacement rate of approximately 4.0% (450 protection systems) per year is required to manage the risk of failure of protection systems.

2.3.3 Asset Assessment Details

<u>Demographics</u>

The ESL for protection systems, outlined in Table 7 below, is classified according to their technology. The variation of ESL by technological vintage is based on generally accepted industry practice and internal experience.

Table 7: Protection Systems Expected Service Life

Protection Technology	***Expected Service Life***
Electromechanical	45 years
Solid State	25 years
Microprocessor	20 years

The average age of the protection system fleet is currently 22 years of age and 21% of the in-service protection systems are currently beyond their expected service life. Assessing the demographics of the individual technology types, 21% of electromechanical systems are operating beyond expected service life, 70% of solid state systems are operating beyond expected service life, and the first generation microprocessor systems have started to reach their ESL with 0.2% of these systems operating beyond expected service life. Furthermore, up to 5% of the current microprocessor system fleet will reach its expected service life within the next 5 years. The demographics of the protection system population are provided in Figure 14.

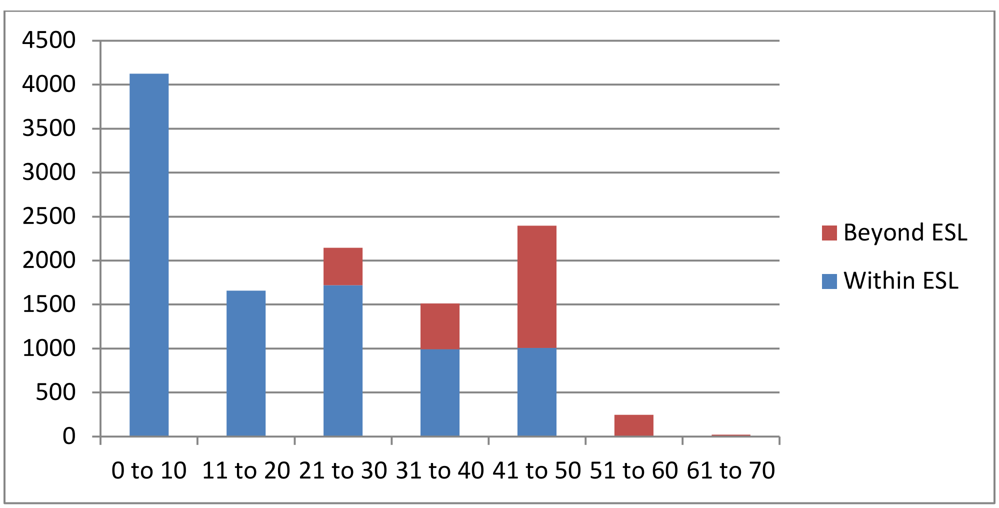


Figure 14: Demographics of Protection Systems Fleet

The potential risks to system and customer reliability as a result of this long term demographic pressure needs to be managed through continuous capital replacement programs. As can be seen in Figure 15, the current replacement rate of 450 protection systems per year will allow the percentage of protection systems beyond ESL to slightly reduce over the next 10 years.

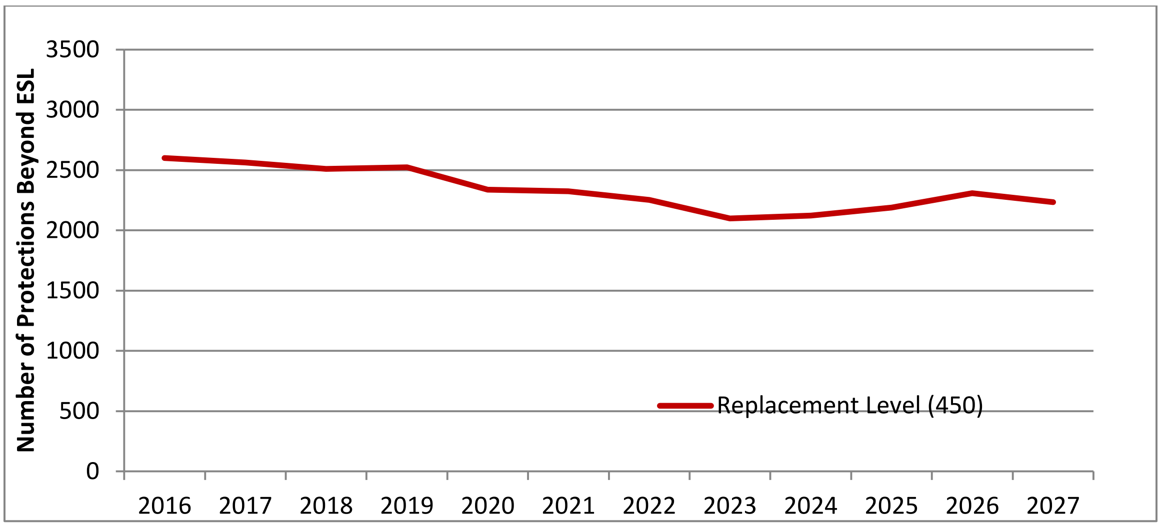


Figure 15: Projection of Protection Systems Beyond Expected Service Life

<u>Performance</u>

The forced outage frequency of equipment caused by protection systems has been declining for lines equipment and a relatively stable trend for station equipment over the past 10 years, as outlined in Figure 16.

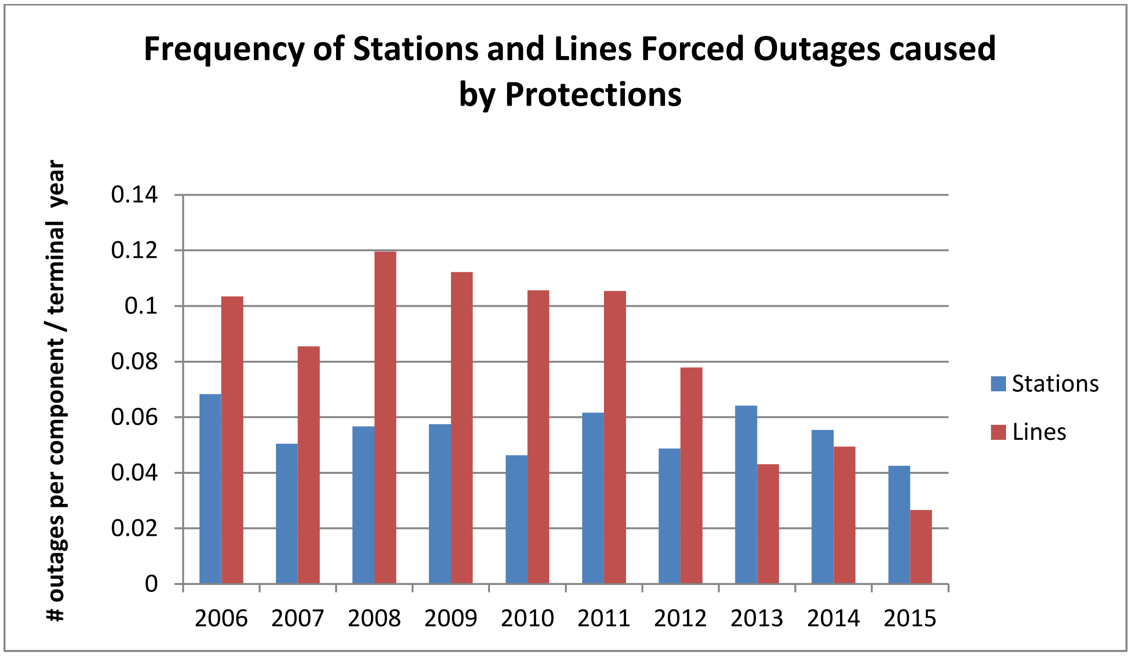


Figure 16: Frequency of Stations and Lines Forced Outages caused by Protections

Protection systems play a critical role in ensuring the safe and reliable operation of the transmission system. The systems must be both dependable (operating when required) and secure (not operating on faults in adjacent protection zones) to ensure the reliability of supply. To mitigate this risk, the protection system replacements in the test years are focused on replacing protection systems that have a high likelihood of causing delivery point interruption and impacting the bulk electricity system.

Programmable Auxiliary Logic Controller (PALC) relays, one type of solid state protection system, have shown an increase in recorded defects and trouble calls over the years. Hydro One has been actively replacing PALC relays and approximately 200 PALCs have been replaced in 2014 and 2015. See Figure 17 below for the historical annual defects. Currently, Hydro One still has approximately 400 PALC relays in the system and plans to replace them over the following five years.

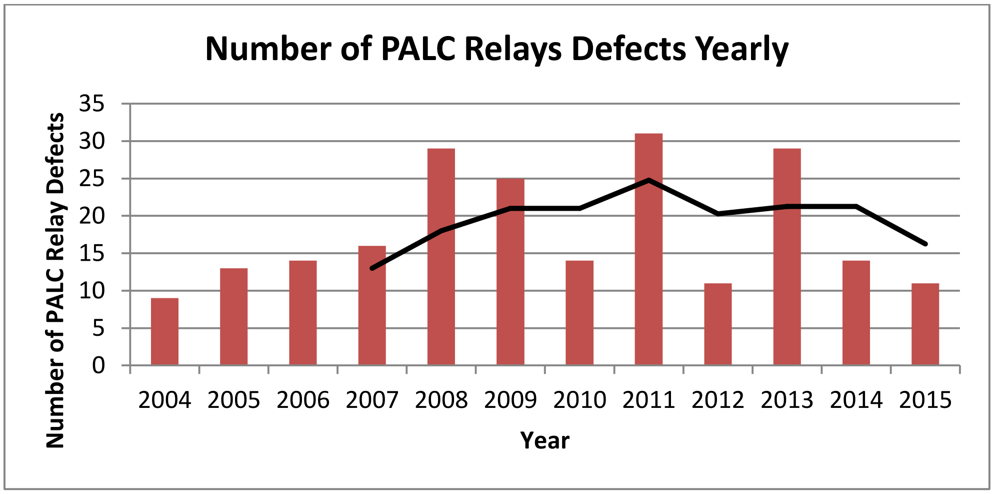


Figure 17: Historic Performance of PALC Relays

<u>Condition</u>

Protection system condition is an important indicator of equipment reliability. Condition is primarily based on age and findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, which can alter the performance of the relay. This is primarily a concern with electromechanical systems, but component aging or defects and thermal cycling can also affect solid state and microprocessor based protection systems. Microprocessor based protections are a relatively new technology, detailed condition metrics and indicators are not as well established. Protection Systems Fleet Condition Assessment is shown in Figure 18.

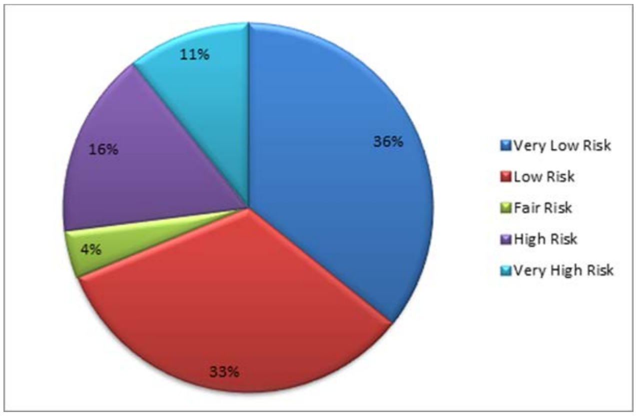


Figure 18: Protection Systems Fleet Condition Assessment

The protection systems which tend to be in the worst condition are also those operating beyond their expected service life or are identified as high risk, such as PALC relays. Maintenance programs and re-verification intervals take into account the limitations and risks associated with each technological vintage to ensure continued and reliable operation. Electromechanical systems, as a result, require more frequent re-verification in contrast to microprocessor based systems to ensure reliable operation. The sustaining capital replacement programs are targeted at replacing protections systems critical to system and customer reliability and with a high or very high risk of failure.

Other Influencing Factors

Other factors driving protection system replacements are summarized below.

- Safety – Operating protection systems beyond their expected service life increases the risk of systems failing to operate and potentially exposing workers and the public to the harm associated with uncontrolled flow of energy. Proactive replacements are required to mitigate this risk.
- Technology Obsolescence – Many protection systems are no longer available, limiting the availability of spares and support; which can adversely impact outage

planning and overall system reliability. This is a significant factor for electromechanical and solid state systems.

- Innovation – New microprocessor based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage. Modern microprocessor protection systems can be deployed with pre-tested configuration settings to facilitate fast and efficient system protection changes to accommodate dynamic changes to the configuration of the transmission system. Extended maintenance intervals for microprocessor based systems help contain OM&A expenditures and reduce life cycle costs.

Table 8: Protection Replacement Rate

Protection Systems Portfolio	Historic			Bridge	Test	
	2013	2014	2015	2016	2017	2018
# of Protection Replacements	340	610	266	367	449	528
% of Fleet	2.8%	5.0%	2.2%	3.0%	3.7%	4.4%

On average, Hydro One has replaced 438 protection systems over 2014 and 2015 and will replace an average of 448 per year, out of 12,100, in 2016 through 2018. Protection and automation bundling approach has been used starting 2013 for any future protection system replacement with in service date planned 2015 and after.

OM&A expenditures are generally consistent year over year with minor variations attributed to time-based scheduling of preventative maintenance. Replacement of electromechanical and solid state protections with modern microprocessor based protection systems is expected to lower future maintenance costs as the new technology allows for extended maintenance intervals.

Protections are a critical component in ensuring a safe and reliable bulk electricity system, and maintaining a reliable supply to customers. Maintaining the fleet in an adequate condition will help preserve reliability in line with good utility practice and regulatory obligations.

3. TRANSMISSION LINE ASSETS

3.1 Transmission Overhead Conductor and Hardware

3.1.1 Asset Overview

Hydro One's transmission system consists of approximately 30,000 circuit km of overhead transmission lines. Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or local distribution companies, including Hydro One Distribution, who in turn distribute the power to customers. Hydro One's transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV.

The bulk of Hydro One's overhead lines are constructed using aluminum conductors reinforced with a steel core (ACSR), as depicted in Figure 19. ACSR is the most prominent type of conductor used on transmission systems. The conductors are supported by steel structures, ceramic insulators and connecting hardware. The lines are protected from lightning strikes by shieldwire mounted above the conductors.

Figure 19: ACSR Conductor

- Currently 19% of the conductor population is beyond its expected service life. At historical replacement rates the conductor kilometers beyond expected service life will increase to 36% in the next 10 years.
- 9% of the conductor population falls within the high risk category. Hydro One expects population of this category to increase as additional condition assessment programs are carried out during the test years.
- The number of forced outage from conductors has declined slightly in recent years while the duration of outages has remained flat.

Given the current demographics of the conductor population, condition trends and the risks associated with conductor failures, an increased rate of conductor assessment and replacements over historic years is required to maintain current levels of system reliability performance.

3.1.2 Asset Strategy

Hydro One's strategy for conductors is to manage the conductor population in a manner that maintains reliability. Hydro One intends to replace approximately 0.6% of conductor in 2017 and 1.5% in 2018, in order to manage risks associated with the declining condition of the conductor population. Hydro One considers condition assessment results, performance data, asset demographics and the consequence of failure to system and customer reliability when making replacement decisions related to conductors.

When a conductor is determined to have reached the point of needing refurbishment, all major components within that line section including the structures, shieldwire, u-bolts and insulators are assessed and refurbished to meet future system requirements. This work of bundling conductor replacement with refurbishment of other transmission line components that also need replacement at the same time is a cost effective approach that is now used when replacing all conductors.

3.1.3 Asset Assessment Details

Demographics

Hydro One uses an expected service life ("ESL") of 70 years for conductors; although this can vary based on several factors, with environmental conditions being the primary factor. The average age of the transmission conductor fleet is currently 52 years and 19% of the conductors are currently beyond their expected service life. The demographics of the conductor population are outlined in Figure 20.

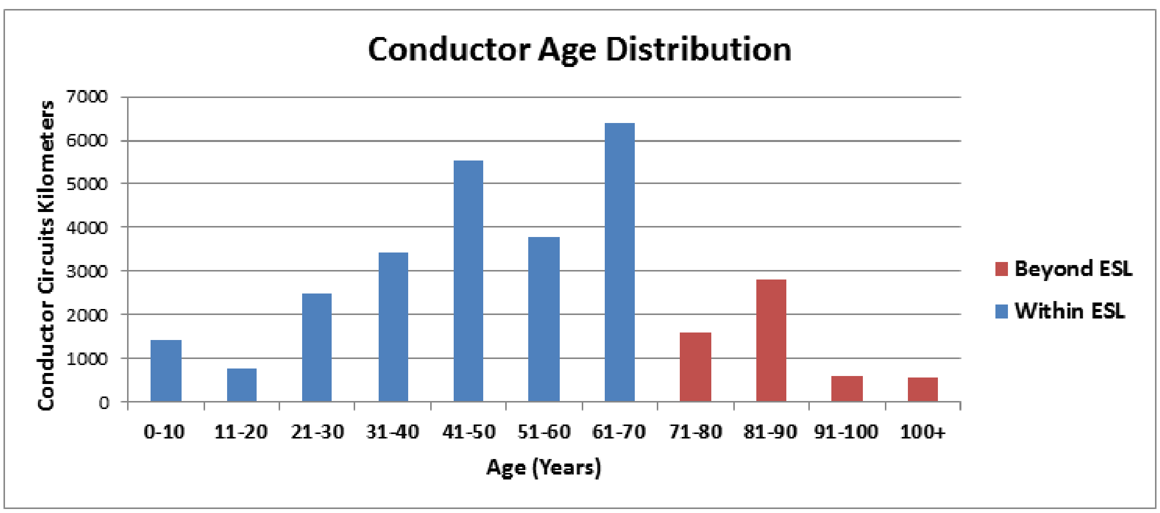


Figure 20: Demographics of Conductor Fleet

Although there have been recent increases in replacement rates to deal with immediate risks, Figure 21 demonstrates that by 2025 the number of conductors beyond their expected service life will increase by over 90%. Hence an increase in future replacements is required to maintain acceptable fleet demographics. If untended, this requirement would significantly increase the risk associated with system and customer reliability, as well as impacting exposure to public safety risks on populated areas, road crossings, and public use of transmission corridors.

The following graph illustrates kilometers of conductors beyond ESL at both historical replacement rate of 120 circuit km/year (average of 2013-2015) and proposed replacement rate of 490 circuit km/year (average of 2017-2026).

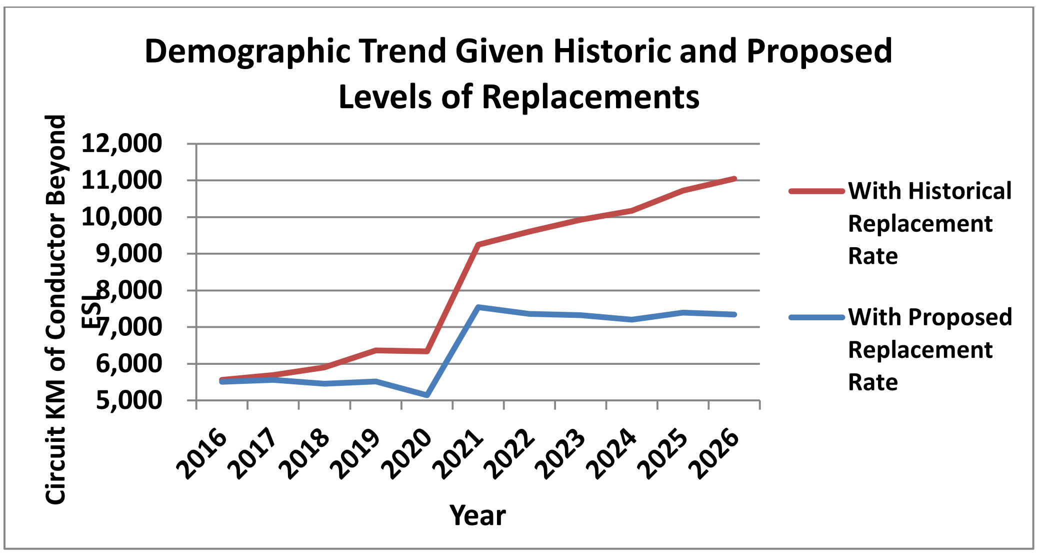


Figure 21: Projection of Conductor Beyond Expected Service Life

Performance

Conductor failure can have very negative consequences both in terms of reliability and safety. The number of forced outages due to conductor failures has improved over the past 10 years, as outlined in Figure 22.

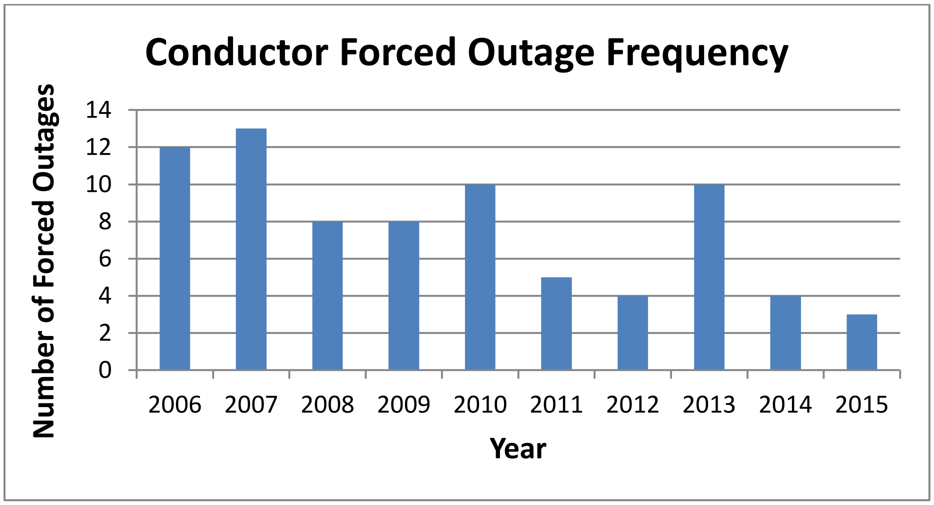
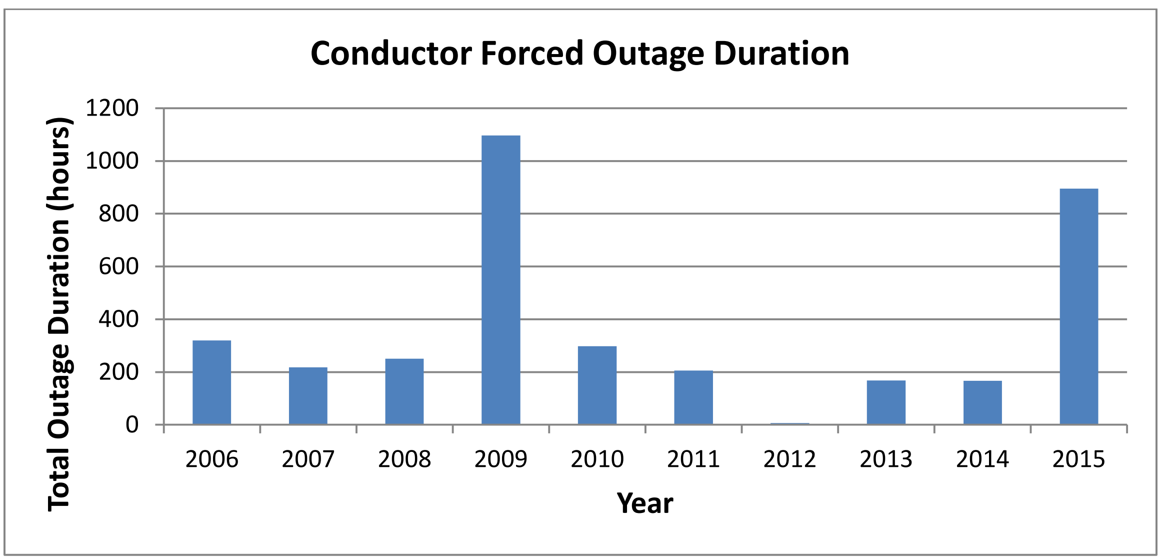


Figure 22: Forced Outage due to Conductor and related Hardware Failures

The forced outage duration due to conductor failure, displayed in Figure 23, demonstrates that conductor outage duration has been relatively stable over the last 10 years with the exception of the abnormality in 2009 and 2015.



**Note: The extreme outage duration in 2009 was due to an emergency conductor replacement on B10H/B20H circuits.*

Figure 23: Forced Outage Duration due to Conductor Failure

Outage frequency and duration performance is anticipated to deteriorate based on the results of condition assessment derived from actual aged conductor sample testing.

Condition

Hydro One executes a condition assessment program to determine the condition of conductors after they reach 50 years of age. The corrosivity of the surrounding environment will have a significant impact on the condition of the conductor.

The results from these assessments and previous studies carried out on life expectancy of conductors indicate that 9% of conductor fleet is known to be high risk, 20% is fair risk, 40% is low risk, and 31% needs assessment as outlined in Figure 24.

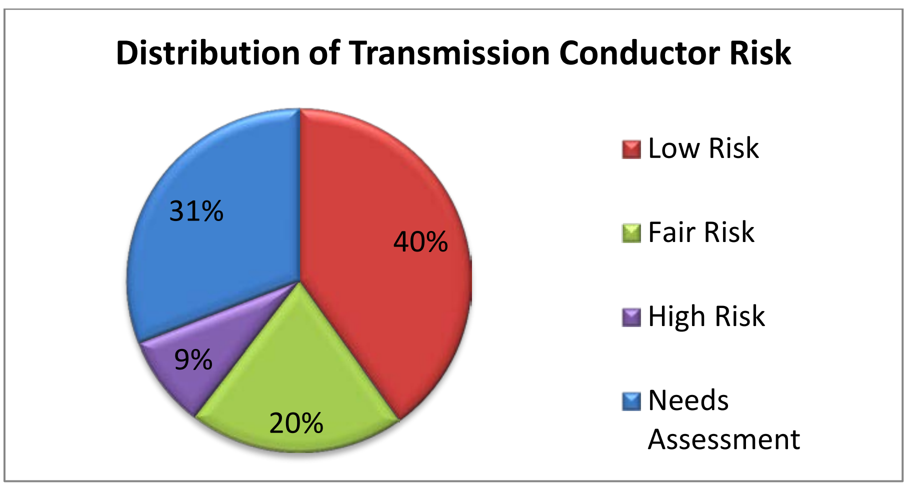


Figure 24: Conductor Fleet Condition Assessment

Hydro One has relied on conductor sample removal combined with laboratory testing as a condition assessment methodology, and is migrating to a remote controlled conductor assessment device that can be used on energized lines, hence eliminating the requirement for conductor sample extraction and line outages. Additional detail on this preventative maintenance work can be found in Exhibit C1, Tab 2, Schedule 2.

Witness: Chong Kiat Ng

Other Influencing Factors

- Aeolian Vibration - Geographical location, line orientation and more importantly conductor tension contribute to level of vibration each circuit experiences, which directly influences the useful lifespan of a conductor. Hydro One has experienced premature conductor failures due to a combination of conductor condition and conductor fatigue due to vibration.
- Safety – Given that transmission lines operate in the public domain, additional consideration must be given to the consequence of failure and potential impact on safety of the public. Factors such as right-of-way use and proximity to road crossings are considered when assessing risk.

Table 9: Conductor Replacement Rate

Conductor Portfolio	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
KMs of Circuit Replacements	22	75	93	201	183	192	440
% of Fleet	0.1%	0.3%	0.3%	0.7%	0.6%	0.6%	1.5%

The need for capital replacement of conductors is expected to increase to an average of 1.7% or 500 circuit km annually in subsequent years, to address the deteriorating condition of the conductor. The circuits being addressed in the bridge and test years have all reached end of life verified through testing and condition assessment.

3.2 Transmission Wood Pole Structures

3.2.1 Asset Overview

Hydro One has approximately 42,000 wood pole structures. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. These wood pole structures are utilized on 230 kV and 115 kV circuits depending on the geographic location and security requirements of the line. The majority of transmission wood pole circuits support radial circuits, and as a result wood pole or cross-arm failure can often result in a direct customer outage.

The two basic transmission wood pole design types in use by Hydro One are “H Frame” design and “Single Pole” design. The H-Frame design consists of two poles and a cross-arm; whereas the “Single Pole” design uses a single pole with steel or wood cross-arms to suspend the conductors.

At the 230 kV circuit level a larger wood pole structure was traditionally used which utilized smaller wood poles as cross-arms to support the insulators and conductors. This structure type is known as the Gulfport type and approximately 5,800 of these where installed on the transmission system beginning in the mid-1960s. However, the small poles used as cross-arms were subsequently found to be defective and suffer from internal rot. Replacement programs over the past 12 years have been focused on eliminating these defective poles from the system.

Figures 25A through 25C illustrate these three different wood pole design types used in Hydro One’s transmission system.

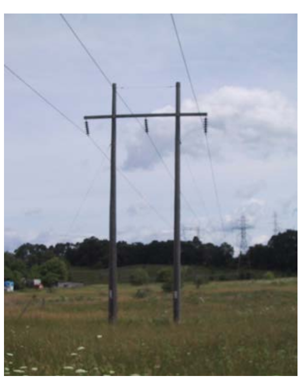


Figure 25A: Wood Pole H–Frame Structure

Figure 25B: Wishbone Structure

Figure 25C: 230 kV Gulfport Structure (with defective/failed cross-arm)

- Currently 27% of the wood pole population is beyond its expected service life.
- The condition of the wood pole fleet, determined through industry standard maintenance practices, is such that 3% present high risks that need to be mitigated.
- The frequency and duration of forced outages for wood poles has shown improvement over the last 10 years. However wood poles failures can have very negative consequence to reliability due to the majority of transmission wood pole circuits supporting radial circuits.

Given the current demographics of the wood pole population, condition and the risks associated with wood pole failures, the continuation of a rate of replacement of 2% is required to maintain current levels of performance and risk.

3.2.2 Asset Strategy

Hydro One's strategy for wood poles is to manage the wood pole population in a manner that preserves reliability and controls costs. Hydro One intends on continuing with a replacement rate of approximately 2% per year to manage risks associated with operating a deteriorating wood pole population and the defective 230 kV Gulfport type structures. Hydro One considers results of wood pole inspections and tests done in accordance with

CSA guidelines, performance data, asset demographics and the consequence of failure to system and customer reliability when making replacement decisions related to wood poles. This will result in a continuation of the strategy to proactively replace wood poles to reduce wood pole failures that impact customer reliability, and minimize emergency response activities that have a higher risk of negatively impacting environmentally sensitive areas.

3.2.3 Asset Assessment Details

<u>Demographics</u>

Based on Hydro One's experience, the normal expected service life ("ESL") used for wood poles is 50 years. Wood poles and cross-arms are normally treated with preservatives in order to prevent premature decay and extend their expected service life. The average age of the wood pole fleet is currently 33 years and 27% of the wood poles are currently beyond their expected service life. The demographics of the wood pole population are outlined in Figure 26.

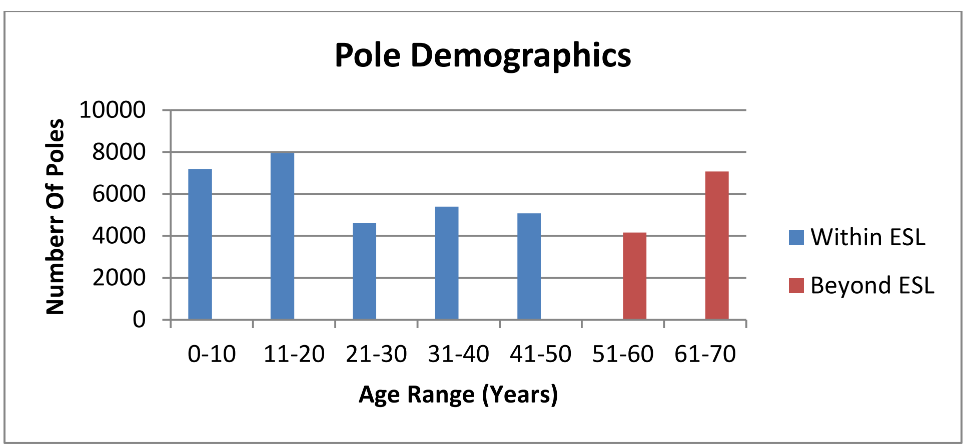


Figure 26: Demographics of the Wood Pole Fleet

Hydro One is proposing to maintain the current historic replacement rate of approximately 2% over the test years. As can be seen in Figure 27, at this rate of replacement the number of wood poles beyond their expected service life will improve from the present 27% to 19% by 2024.

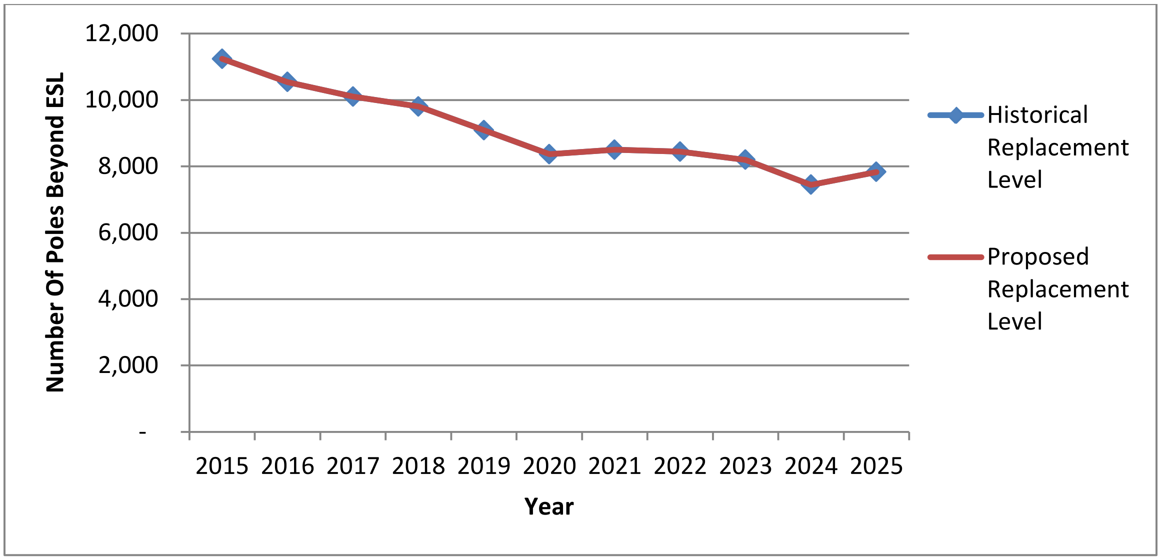


Figure 27: Projection of Wood Poles Beyond Expected Service Life

<u>Performance</u>

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm can often result in a direct customer outage. Many of these northern wood pole circuits feed major industrial customers and without an adequate supply of power, these customers are often forced to shut down until power is restored.

The number of forced outages due to wood pole structure failures has improved over the past 10 years, as outlined in Figure 28, based on the current rate of replacement to address end of life wood poles and the reduction of the higher risk defective Gulfport structures on the system.

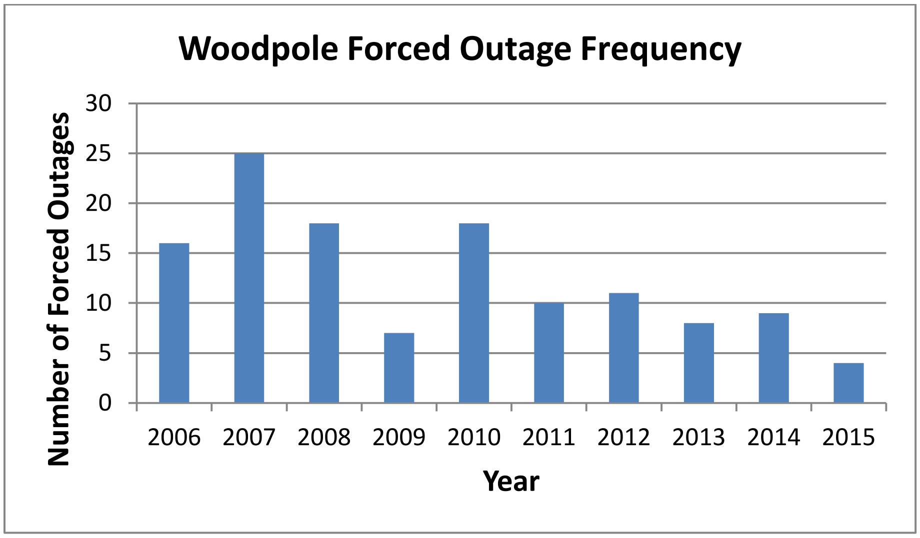


Figure 28: Forced Outages Due to Wood Pole Failures

The forced outage duration due to wood pole failures, displayed in Figure 29, demonstrates improvement over the past 10 years, except for the extreme spike in 2010. This type of year is not unexpected given many of these circuits are radial supplies and in remote locations, with difficult access.

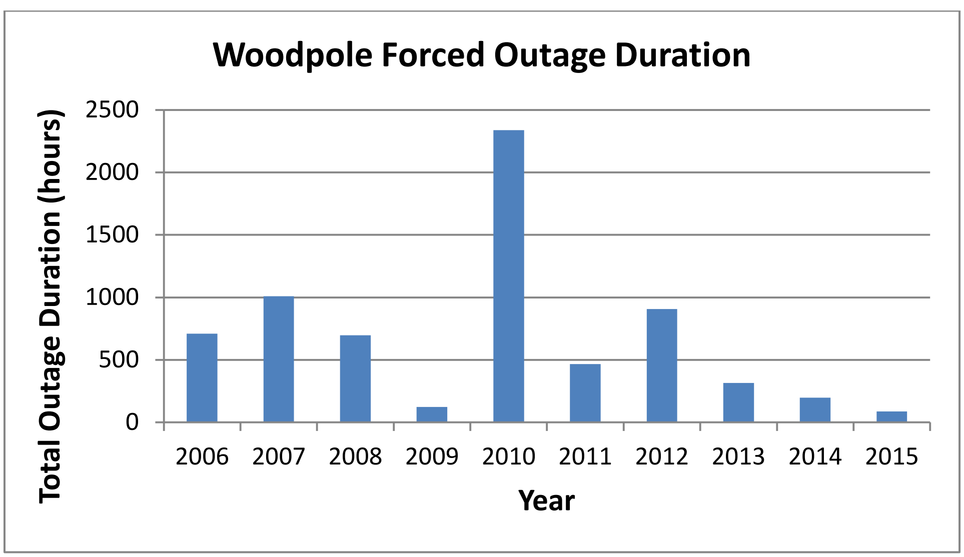


Figure 29: Forced Outage Duration due to Wood Pole Failures

At the current rate of replacement, the frequency and duration of outages is expected to remain consistent with recent years.

<u>Condition</u>

Wood structures deteriorate over time; the rate of deterioration depends on location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Wood pole structures are comprised of either a single pole or multiple wood poles with a wood cross-arm which is bolted to the poles to support the insulator strings and conductors. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Wood pole assessments are undertaken to inspect the condition of cross-arms and pole tops, and to evaluate the soundness of the wood near the ground line, which is consistent with industry practices. Based on the current condition assessment, 3% of Hydro One's wood pole population is high risk, as outlined in Figure 30. The assessment is regularly updated as new conditions are reported or factors are considered. Approximately 6% of the wood pole population needs to be assessed to determine their condition risk, 20% is fair risk, and 71% is low risk.

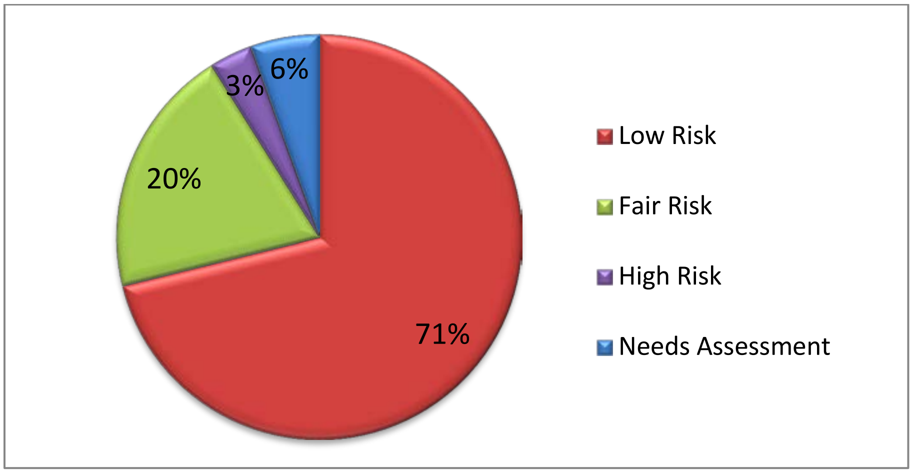


Figure 30: Wood Pole Fleet Condition Assessment

The number of poles reaching end of life identified each year through condition assessments is consistent with the current replacement rate, and hence the number of wood poles in fair and high risk condition is expected to remain stable. The number of poles replaced historically and planned for the bridge and test years is displayed in Table 10 below. As a result, reliability and safety risks will be in-line with past performance which has been improving in terms of outage frequency and duration over the past 10 years.

Table 10: Wood Pole Replacement Rate

Wood Pole Portfolio		Historic			Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
# of Replacements	763	480	897	845	850	850	850
% of Fleet	1.8%	1.2%	2.2%	2.0%	2.0%	2.0%	2.0%

The capital replacement rate in the test years remains consistent with the bridge year and historic levels. Continued renewal of the fleet at this rate has been very effective at keeping pace with the number of structures that reach their expected service life.

Hydro One has also started using composite pole technology to replace wood poles. Composite pole technology has the potential to reduce long-term maintenance cost. Currently 25% of the poles replaced in any given year are with composite material. This will allow for evaluation of this emerging technology product to determine if life cycle cost management of these assets can be reduced.

3.3 Transmission Steel Structures

3.3.1 Asset Overview

Hydro One has approximately 52,000 steel structures on the transmission system to support the transmission lines across the province. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 500 kV.

Steel structures are manufactured from carbon steel and protected by hot dip galvanizing (HDG), a zinc based product to protect the steel from corrosion. Based on the studies conducted by corrosion experts such as Electric Power Research Institute (EPRI), the service life of steel structures is primarily depended on the condition of its HDG, as once a structure has lost its galvanizing protection the carbon steel is exposed to the environment, and the corrosion rate of the structure accelerates by a factor of 8-10 times.

Based on Hydro One's and industry experience, the expected service life of HDG steel can be anywhere from 35 to 140 years in Ontario depending on the locations where they are installed.

If steel corrosion is not addressed prior to corrosion setting in, the steel structure will begin to lose structural strength and the only option would be partial or complete replacement of the tower. See figures 31A through 31D below which display towers newly coated as well as towers with corrosion. When loss of structural strength diminishes below its design strength, integrity and capacity of the structure is compromised and a failure may occur under certain weather loading conditions.

Recoating the structure with zinc-based product will provide on-going protection to the underlying carbon steel and preserve the steel structure. Given the condition and the risks associated with steel structure failures, an increase in the fleet renewal is required to avoid tower failure, negative impacts to reliability and increased costs for tower replacements.

Figure 31A: Steel Tower Structure

Figure 31B: Hot Dip Galvanized Steel Tower Structure

Figure 31C: Steel Tower with Corrosion

Figure 31D: Steel Tower Recoated

3.3.2 Asset Strategy

Hydro One's strategy for steel structures is to manage the fleet through a combination of planned structure replacements, component refurbishments and tower coating in order to maintain reliability of the system. Structure replacements and component refurbishments are usually part of line refurbishment and are described earlier in this section. This investment category focuses on preserving structures through a tower coating program.

Based on International Organization for Standardization (ISO) the environment is divided into six atmospheric corrosivity categories. In accordance with ISO 12944 and a study completed by EPRI, the province of Ontario is divided into four corrosion zones ranging from C2 to C5. Each of these corrosion zones has a range of corrosion rates which can be used to estimate the service life of HDG steel based on its location. C2 and C3 zones are defined as light corrosion zones and the towers located in these two zones will likely have the original galvanizing protection layer for at least 140 years. This means towers will be protected and maintained in good condition for minimum of 115 years without requiring any coating. Based on Hydro One asset records, there are approximately 39,000 steel structures in these light corrosion zones and 2,200 of them are older than 100 years. However, none of them are older than 115 years and there is no immediate tower coating needs for structures within these zones.

C4 & C5 zones are defined as heavy corrosion zones which have very high corrosion rates for zinc and carbon steel (See Figure 32 below). Based on EPRI study, the towers will lose their protective zinc in 35-65 years after installation. Furthermore they would lose 10% of their metal in the following 30-60 years. At this stage, structures are no longer able to withstand the original design loads and either a major refurbishment or complete tower replacement would be required.

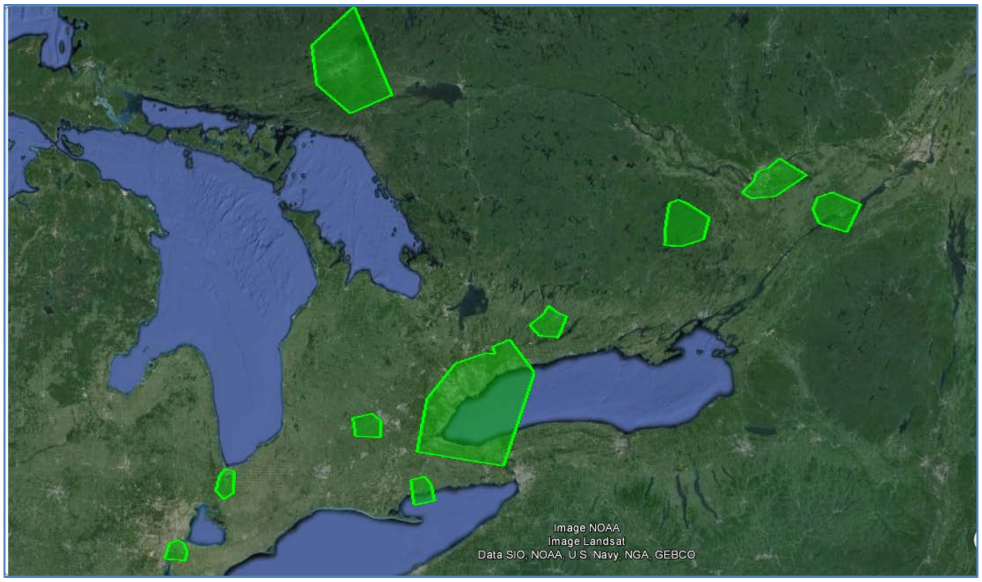


Figure 32: C4 & C5 corrosion regions in Ontario (courtesy of EPRI).

An effective tower coating program can maintain a steel tower structure at its design capacity indefinitely by re-application of the coating approximately every 35 to 65 years.

If towers are not re-coated prior to corrosion and metal loss, the opportunity is lost and the tower will ultimately have to be replaced.

3.3.3 Asset Assessment Details

Demographics

Hydro One has approximately 52,000 steel structures; the demographic of the steel structure population is outlined in Figure 33. There are approximately 13,000 steel structures are located in heavy corrosion zones such as Windsor, Sarnia, Hamilton and GTA. 7,500 of them currently meet tower coating criteria and approximately an additional 4,700 steel structures will meet this tower coating criteria over the next 10 years if the historical coating rate is maintained. The demographic of the steel structures in heavy corrosion zones are outlined in Figure 34.

Hydro One uses an average expected service life ("ESL") of 80 years for steel structures if the structures are not re-coated. Currently 2,100 structures in high corrosion zones are beyond ESL and exceed the coating criteria. These structures will need detailed engineering assessment and potentially require heavy refurbishment or even complete replacement.

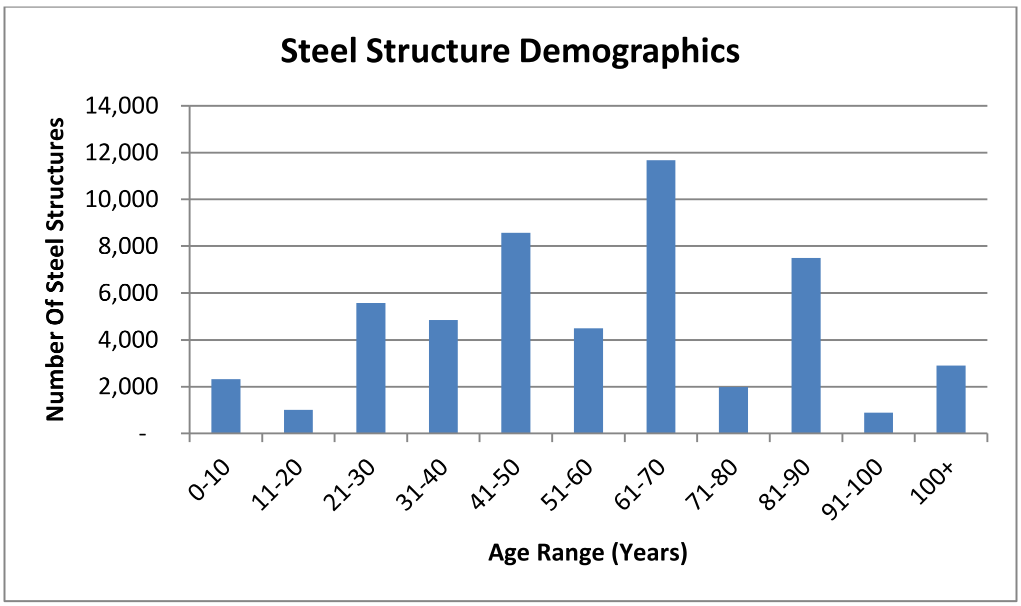


Figure 33: Demographics of Steel Structure Fleet province wide

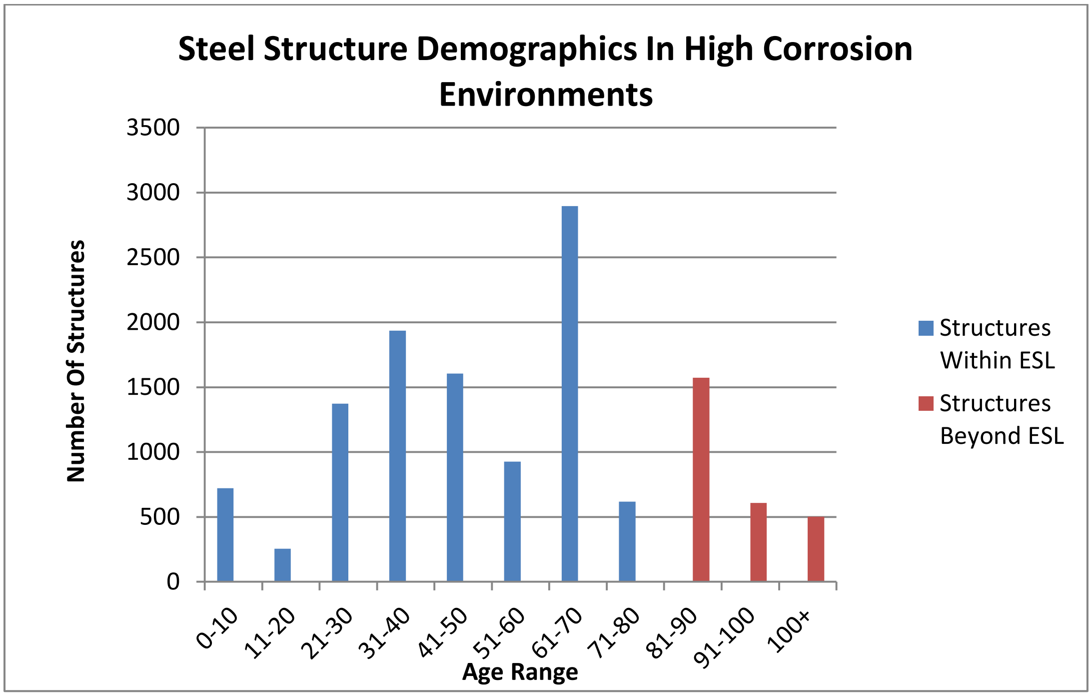


Figure 34: Demographics of Steel Structure Fleet in Heavy Corrosion Zones

Based on the historical data, the average rate for structure renewal is about 200 towers per year. As outlined in Figure 35, at historic tower coating rates, the steel structures requiring coating in high corrosion zones will increase by 34% in 10 years. However, with planned coating plan, all structures requiring coating will be coated in the next 10 years.

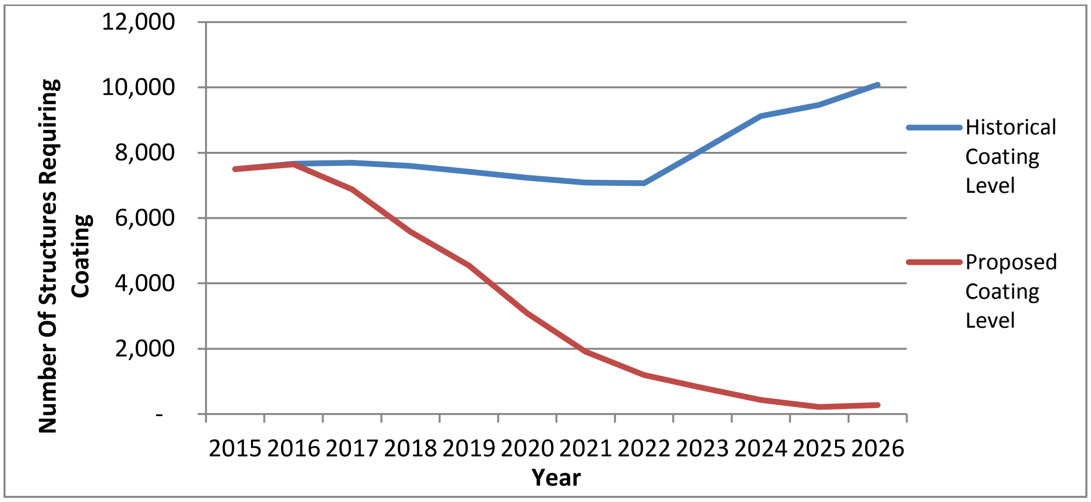


Figure 35: Projection of Steel Structures requiring Coating

<u>Performance</u>

Forced outages for steel structures represent the number of times an outage is caused by steel structure failure such as complete tower collapse, or a broken (or bent) tower member. It excludes forced outages caused by external interferences such as animal contact and weather related incidents.

The number of forced outages due to steel structure failures has shown slight decrease over the past 10 years as outlined in Figure 36. With the current condition of the steel structures and the demographics of the fleet, it is expected that increased capital programs will be required to prevent future increases in forced outages due to steel structure failures.

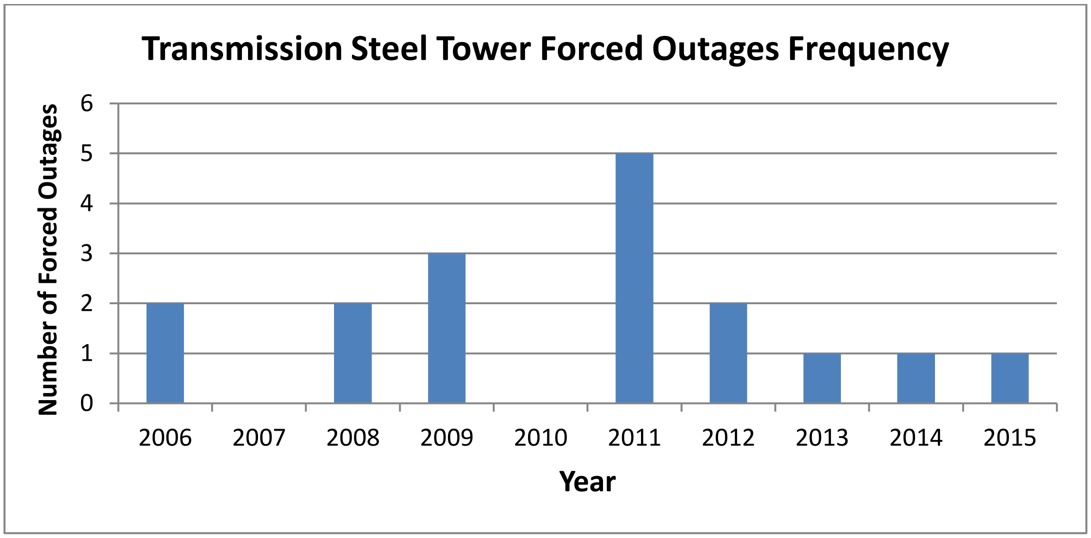


Figure 36: Forced Outages due to Steel Structure Failures

The forced outage duration due to steel structure failures, displayed in Figure 37, demonstrates a stable outage duration trend over the last 10 years, except for the spike in 2011. This type of spike is not unexpected given the very remote locations of some of the circuits with difficult access. This can place considerable strain on the system as it may result in loss of supply to large customers including local distribution companies and generation connections.

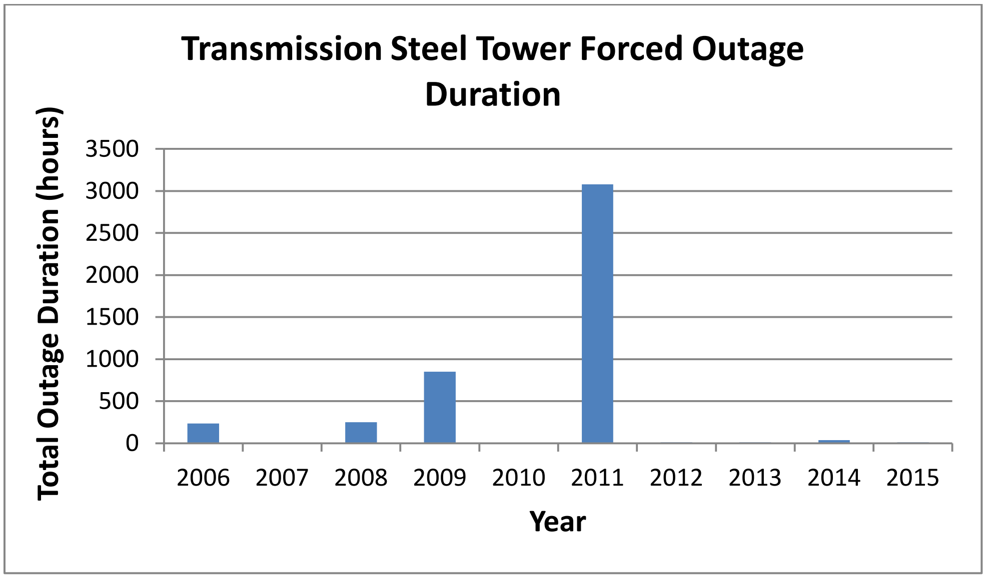


Figure 37: Forced Outage Duration due to Steel Structure Failures

<u>Condition</u>

Transmission steel structure condition assessment is initiated based on demographics, geographic zone and result of study conducted by industry experts over the past several years. The initial assessment results will be verified by the established Hydro One maintenance program which includes inspections, patrols and detail corrosion assessment. Towers are visually inspected in accordance with NACE ("Nation Association of Corrosion Engineers") guidelines on the degree of corrosion. Detailed corrosion assessment includes climbing towers and measuring the remaining thickness of protective coating, loss of metal if any and assessment of bolts and fittings.

Based on the current assessment, 4% of Hydro One's steel structures require major refurbishment or replacement as outlined in Figure 38. 14% of the steel structures require coating and will be addressed in the steel structure coating program. This assessment is continuously reviewed and updated as more structures meet the coating criteria every year.

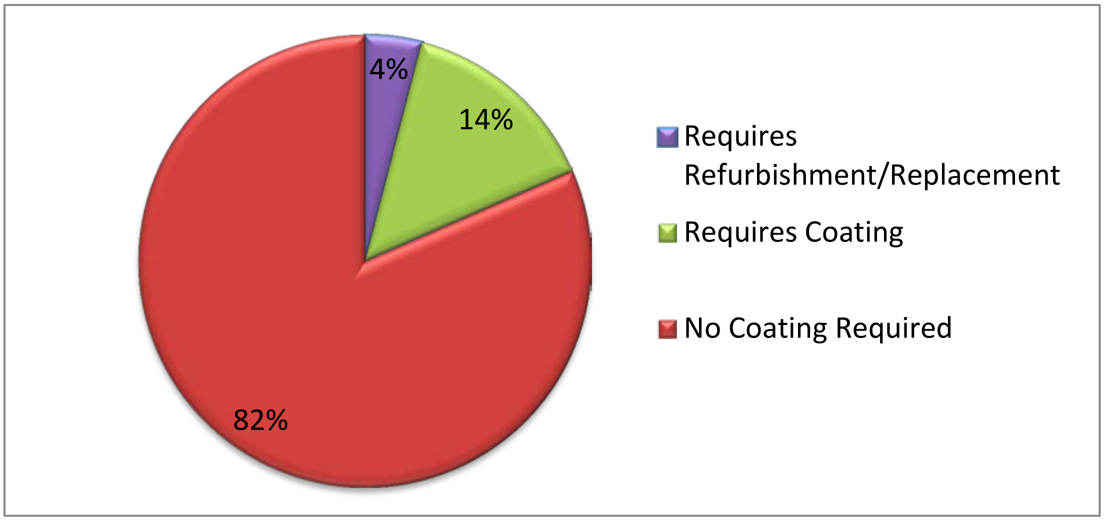


Figure 38: Steel Structure Fleet Condition Assessment

In order to maintain the condition of the fleet, the rate of refurbishment/coating will need to be increased as per Hydro One's investment plan.

Other Influencing Factors

- Innovation - Hydro One is continuing to investigate the use of alternative coating products in order to reduce the cycle time involved in the re-coating process by potentially reducing the amount of steel surface preparation and decreasing the drying time which is coating product dependent. This will reduce outage time, when required, and permit a higher number of towers to be coated each year.
- Work Method – A revised work method has been established that allows for tower coating in live line conditions. This live line work method will minimize the outage constraints and maximize the quantity of towers to be coated.

Table 11: Steel Structure Replacement

Steel Structure Portfolio		Historic			Bridge	Test	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
# of Renewal	228	235	121	300	462	1250	1600
% of Fleet	0.4	0.5%	0.2%	0.6%	0.9%	2.4%	3.1%

The capital investment in the test years is an increase over historic levels. The strategy to manage the fleet of steel towers is a combination of planned replacements, component refurbishment and tower coating. The number of towers that have been refurbished, coated, or replaced over the past 10 years has been very low. As a result of recent condition inspections and tower coating studies the rapid deterioration of steel structures in highly corrosive areas needs to be addressed with an increase in the fleet renewal rate. Hydro One plans to undertake an aggressive tower coating program to sustain these assets. Tower coating has been identified as the preferred alternative as it has a significant life cycle cost advantage and has less impact to the system as circuit outages required for coating are minimal.

3.4 Transmission Lines Insulators

3.4.1 Asset Overview

Transmission line insulators are an integral component of the transmission system. They mechanically support and electrically insulate the conductor from the structure and must provide sufficient dielectric strength to prevent short circuits to ground. There are approximately 420,000 insulator strings in Hydro One’s overhead transmission network. They are assessed through visual inspection, infrared thermography and in-situ live-line electrical testing. Insulators are categorized into three types; porcelain, glass and polymer as described below and depicted in Figure 40.

Glass Insulators:

Hydro One (as Ontario Hydro) began installations of glass insulators in the mid-1980s. These insulators are expected to last the life of the circuits and do not require replacement until the entire line will be refurbished. The only exception would be to address shattered insulator units due to external factors such as occasional vandalism or lightning strikes.

Porcelain Insulators:

Porcelain insulators are the oldest insulator type used by Hydro One. Porcelain insulators have been used by Hydro-Electric Power Commission of Ontario (the predecessor of Ontario Hydro and Hydro One) since 1910. Similar to glass insulators, high quality porcelain insulators are expected to last the life of the circuit and do not require replacement until the entire line will be refurbished.

Polymer Insulators:

Polymer insulators were developed as an alternative to porcelain and glass, and Hydro One (as Ontario Hydro) began installing polymer insulators at 115 and 230 kV in the mid-1980s. It is estimated that their life expectancy is considerably shorter than glass and porcelain insulators and at this time, Hydro One is estimating an average life span of about 30 years for this type of insulator.

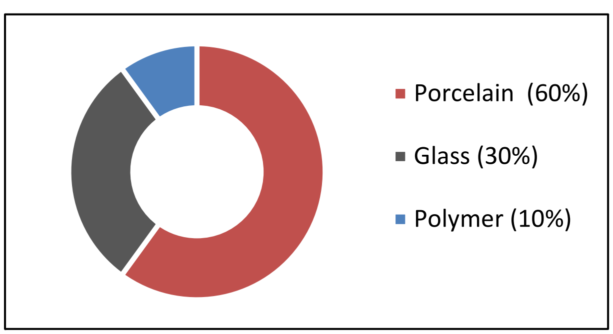


Figure 39: Insulator Types

Insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1965 and 1982 suffer from a phenomena known as cement expansion or cement growth, as shown in Figure 40 below. The purpose of the cement is to bond the pin to the porcelain. Excessive cement expansion of these insulators would create cracks in the cement and porcelain shell resulting in two possible failure modes:

1. Mechanical Failure causing a conductor drop; and
2. Electrical Failure where the cracked porcelain reduces insulating properties.

As a result, some of these insulators will fail prematurely. Factors such as mechanical load and environmental conditions may also cause premature failure. However cracks in the cement and porcelain shell are not always visible or detectable, which along with the number of insulators in the system, make it difficult to predict which insulators will fail. For example, recently Hydro One experienced an insulator failure on its V76R circuit. In March 2015, the centre phase insulator on V76R failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. This type of failure represents a significant public safety risk. As a result, in 2016 Hydro One implemented an insulator replacement strategy.

Figure 40: Porcelain Insulator Unit Affected by Cement Expansion

3.4.2 Asset Strategy

Hydro One's strategy for insulators focuses on the polymer insulators and defective COB and CP porcelain insulators in public areas due to the public safety concerns. These public areas include locations near highways, roads, railways, parks, and golf courses. Hydro One estimates it will take approximately four years to replace the 15,000 circuit structures with these insulators in high risk areas.

Performance

A significant number of transmission insulators are located on high risk structures. As a result, insulator failures, which often result in a conductor drop, could pose serious safety hazards.

The number of forced outages and the duration of the outages due to insulator failure have some degree of variability each year, but have remained within a fairly stable range over the past 10 years, as demonstrated in Figures 41 and 42.

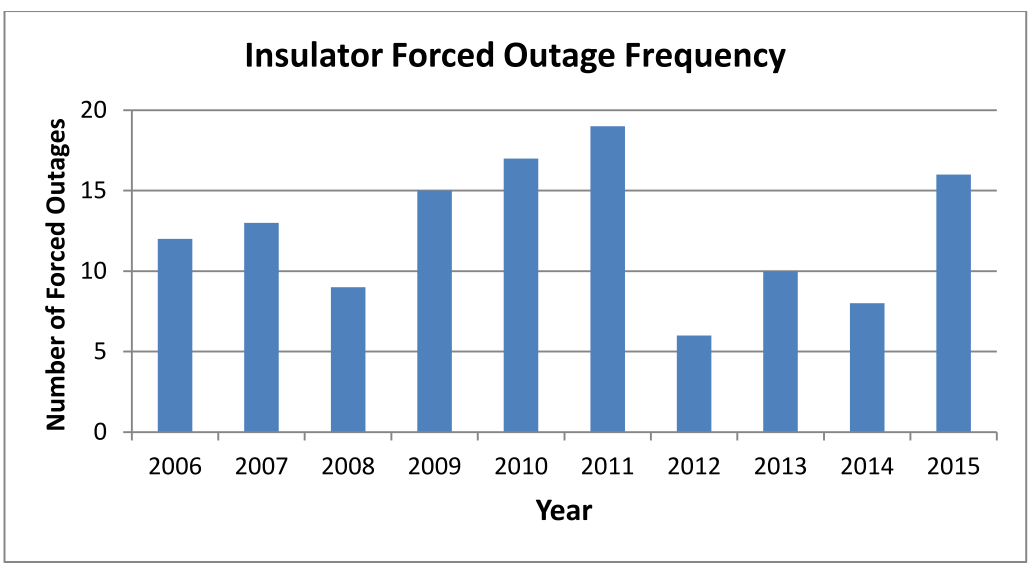


Figure 41: Forced Outages due to insulator Failures

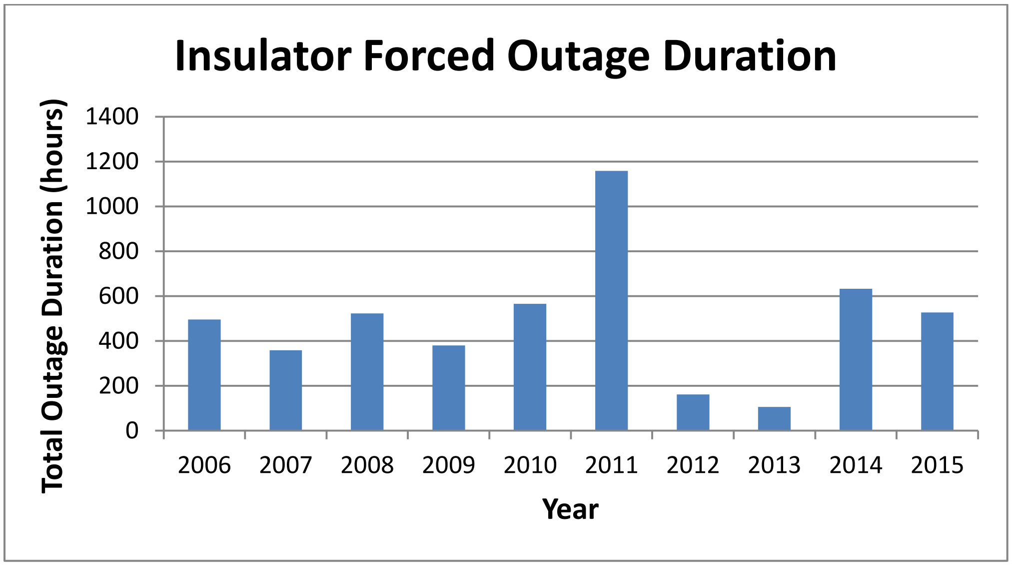


Figure 42: Forced Outage Durations due to insulator Failures

<u>Condition</u>

There are approximately 34,000 circuit structures with defective COB or CP insulators and roughly 15,000 of these circuit structures have been identified as high risk. High risk structures include structures at road crossings, water and rail crossings and structures near urban areas, golf courses, educational and health care facilities. This translates to approximately 60,000 strings of defective insulators which will be replaced in the next four years. Furthermore, there are an additional 60,000 insulator strings containing these defective insulators which are outside of high risk areas, but will adversely affect system reliability should they fail and cause outages.

The historic replacement rate and planned replacements for the bridge and test years are provided in Table 12 below.

Table 12: Insulator Portfolio Replacement

Insulator Portfolio	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
# of circuit structures	210	433	233	155	2100	4030	3880
% of Fleet	0.15%	0.3%	0.2%	0.1%	1.4%	2.7%	2.6%

3.5 Transmission Underground Cables

3.5.1 Asset Overview

Hydro One's transmission system consists of approximately 270 km of underground cables that supply city centres in Toronto, Ottawa and Hamilton with short sections in London, Sarnia, Picton, Windsor and Thunder Bay. Transmission underground cables are typically extensions to, or links between, portions of the overhead transmission system operating at 230 kV and 115 kV. Underground cables are mainly used in urban areas where it is either impossible, or extremely difficult to build overhead transmission lines due to legal, environmental and safety reasons.

Depending on the cable design the three phase conductors may be contained together within a steel pipe or with each phase conductor self-contained in its own sheath and installed separately underground. Transmission underground cables are systems, similar to transmission lines, made up of numerous components all of which need to integrate and function properly in order to deliver power with the reliability that is demanded.

There are three different types of high voltage underground cables in use on the transmission system: Low Pressure Oil Filled ("LPOF") cables, High Pressure Oil Filled Pipe-Type ("HPOF") cables, and Extruded Cross Linked Polyethylene ("XLPE") cables.

Figures 43A through 43C illustrate the three types of underground cables used in Hydro One's transmission system.

Figure 43A: LPOF Cable

Figure 43B: HPOF Cable

Figure 43C: XLPE Cable

- Currently 19% of the underground cable population is beyond its expected service life. Continuing at the historic rate of replacement, the number of underground cables beyond their expected service life would increase to 40% by 2025.
- The condition of the underground cable fleet, determined through industry standard maintenance practices, is such that 4% present high condition risk that need to be mitigated.
- The number of forced outages and duration for underground cables has shown slight improvement over the last 10 years. However, due to the nature and construction of these assets, failures can result in significant reliability and environmental impacts.

3.5.2 Asset Strategy

Hydro One has employed and will continue with its rigorous maintenance program (involving inspections, analysis, and diagnostic testing of cables, vaults, jackets and potheads) that extends the life of these assets. Hydro One plans to continue forward with an average replacement rate consistent with the bridge year in order to manage the reliability and environmental risks associated with operating an aged underground cable population.

3.5.3 Asset Assessment Details

Demographics

Hydro One uses a normal expected service life ("ESL") of 50 years for underground transmission cables, which is based primarily on the original design expectations. However, due to the best practice maintenance program and low historical electrical loadings these cables have been subjected to, a number of cables beyond this age are still in satisfactory operating condition. The average age of the underground cable fleet is currently about 37 years and about 19% of cables are beyond their expected service life.

The demographics of the underground cable population are outlined in Figure 44.

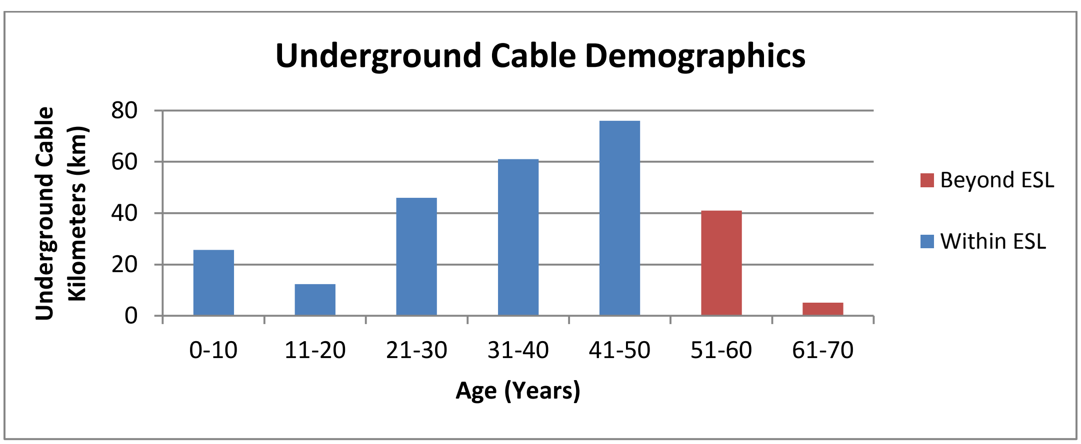


Figure 44: Demographics of Underground Cables Fleet

The potential risks to reliability and safety as a result of the aging demographics and deteriorating cable condition needs to be managed through a continued rigorous maintenance program to detect developing defects, as well as through capital replacement programs. As can be seen in Figure 45, continuing at the historic rate of replacement would result in the percentage of underground cables beyond their expected service life increasing to 40% by 2025. At the proposed replacement rate, the percentage of underground cables beyond their expected service life still will increase from 19% to 35% by 2024.

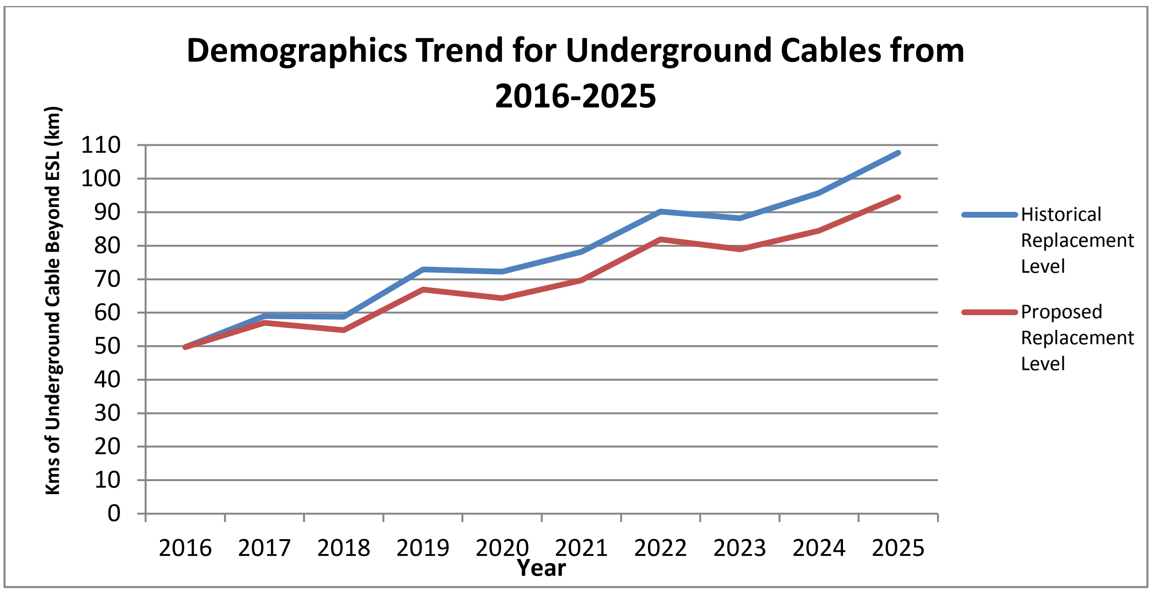


Figure 45: Projection of Underground Cables Beyond Expected Service Life

<u>Performance</u>

The number of forced outages due to a failure on part of the underground cable system has shown a slight improvement over the past 10 years, as outlined in Figure 46. There have been a number of major component replacement projects during the past 10 years including joint, termination, oil pressure system and bonding upgrades which have contributed to this reduction in the forced outages.

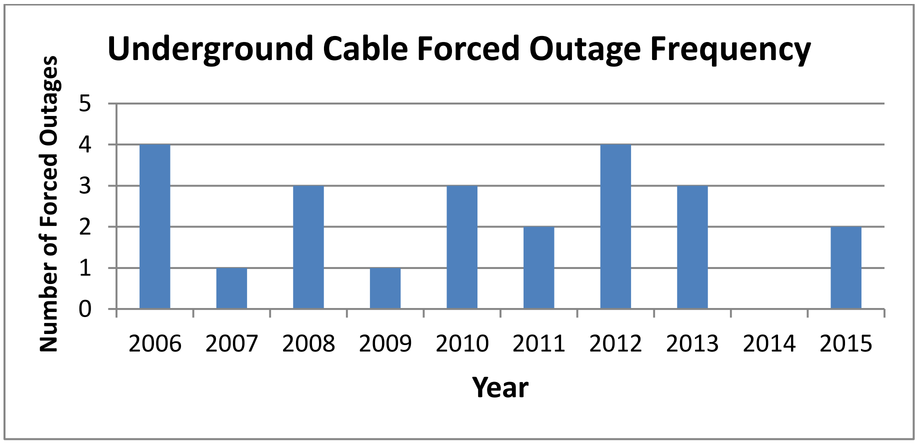


Figure 46: Forced Outages due to Underground Cable Failures

The forced outage duration of each occurrence was increasing significantly during the period from 2008 to 2011 but has been minimal during the last four years, as depicted in Figure 47. This recent decrease is mainly attributable to the replacement of two high risk end of life cable circuits H2JK and K6J.

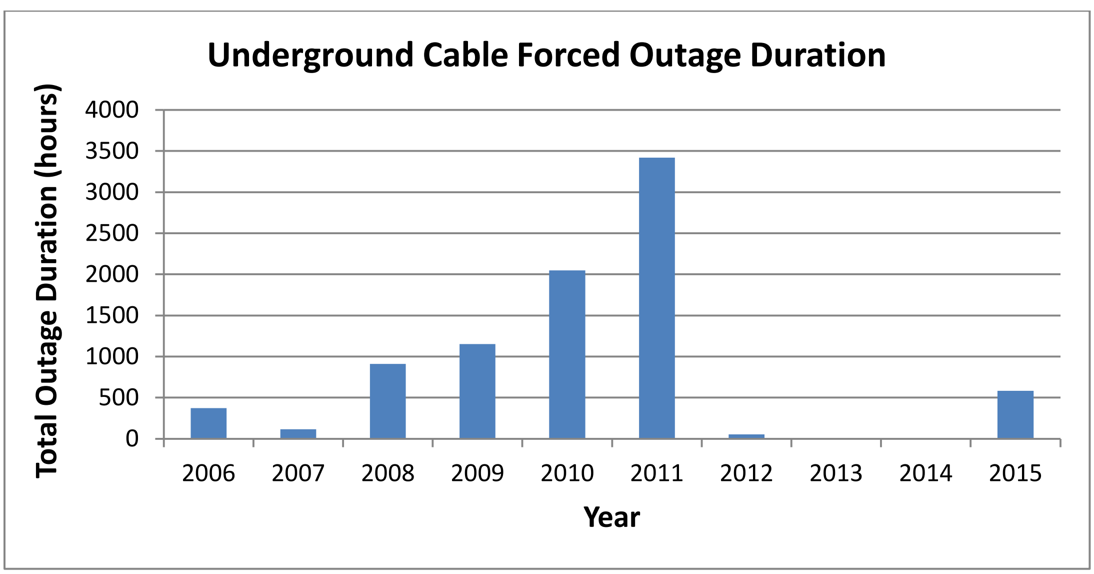


Figure 47: Duration of Forced Outages due to Underground Cable Failures

The forced outage statistics depicted in Figure 47 and 48 are for failures that were significant enough to require the circuit to be forced out of service. There are many other cases where equipment defects and cable leaks have occurred but were not severe enough to force the circuit from service, but instead were addressed under a planned outage.

Condition

Hydro One assesses its underground cable fleet condition based on a variety of factors. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Not all sections of a buried cable are accessible for maintenance inspections and diagnostics, but the inspections are generally representative of the entire cable system.

Based on the current assessment of the underground cable fleet condition, 4% of Hydro One's underground cable population is high risk, 22% fair risk, 73% low risk, and 1% need assessments.

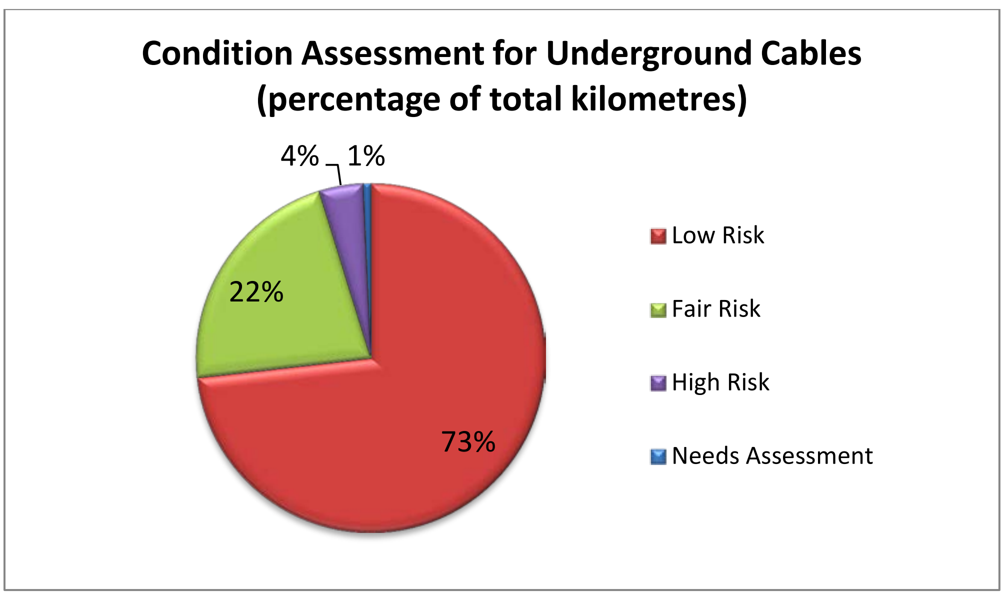


Figure 48: Underground Cable Fleet Condition Assessment

Other Influencing Factors

Other factors driving the increase in underground cable replacements are summarized below:

- Technical Obsolescence – There are some types of underground cables technology that are no longer available and supported by manufacturers. This is a significant factor for low pressure oil filled cables that rely on gravity feed oil reservoirs that are no longer available.
- Environmental Impacts – The failure of an underground cable can result in the leakage of oil into the surrounding area. In 2003, a downtown Toronto cable circuit (H3L) failed which resulted in 5,500 litres of oil spilling into the Don River. The failure was located and repaired, which took over a month to complete. When the circuit was returned to service, it failed again after only 2 months at another location, indicating the need to replace.
- Equipment Loading – Cables are located in major cities where loading has increased significantly since original installation impacting the aging process as well as the number of cable failures.
- Criticality – Underground cables are used to supply the load of major cities, thus a failure of the cable can result in significant impact to customers. In 2010, a downtown Toronto cable circuit (H2JK) failed, since the other supply circuit (K6J) was on a planned outage at the time, the failure of the cable caused all of the five delivery points at Strachan TS to go out of service. The longer term major risk was if the condition of these two circuits deteriorated to a level that was impractical to repair, then both circuits would have to be removed from service resulting in considerable strain and risk to the system for a prolonged period of time.

Table 13: Underground Cable Replacement

Underground Cable Portfolio	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
Kms of Circuit Replacements	0	5.0	3.1	0	0	0	4.8
% of Fleet	0%	1.9%	1.1%	0%	0%	0%	1.8%

Hydro One is now entering into a period where the underground cable circuits are approaching their end of expected life and in order to effectively manage the underground cables continued renewal of the fleet must be maintained. There is some variability in capital expenditures year over year, which is mostly a function of the timing and magnitude of individual projects. The replacement of older oil filled cable systems with new XLPE cable systems, which have lower maintenance costs, will result in lower lifecycle costs.

OM&A expenditures are relatively stable year over year in order to carry out assessment activities to provide insight into cable condition.

Many factors drive cable replacement; the key factors include condition, performance, obsolescence, age, circuit criticality, and environmental impacts. Failure of underground cables can take significant time to repair or replace. This can place considerable strain on the system as it may restrict outages required for maintenance or repair of other equipment. Overloading other cables and related elements can place the system at risk of failure, loss of supply and blackout to the customer.

DEVELOPING THE INVESTMENT PLAN

1. INTRODUCTION

This Exhibit details the investment planning process that takes identified investment needs, turns them into candidate investments, and then inputs them into a prioritization process that yields an investment plan.

The investment planning process draws upon the previous year's efforts to identify investment needs, evaluating and prioritizing proposed individual investments that address these needs, based on the business objectives. The end product is a fully prioritized investment plan.

The key steps in developing the investment plan are shown in Figure 1 below.

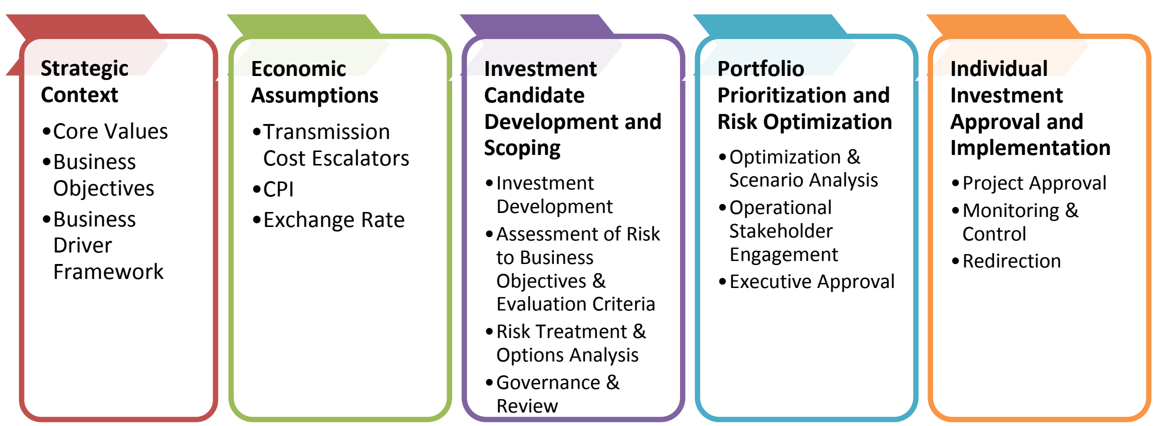


Figure 1: Investment Planning Process

2. STRATEGIC CONTEXT

The annual investment planning process begins with a confirmation of core values and business objectives, which are described in Exhibit B1, Tab 1, Schedule 2. Hydro One's core values are translated into business objectives that inform a series of business drivers based upon which investment proposals are assessed. The business drivers are assigned weights by Hydro One's investment management group, based on their relative importance to the company. They are measured by a set of risk-based outcome-based factors which form the evaluation criteria against which candidate investments are developed, risks are managed, and trade-offs between investments are made in the prioritization process.

Table 1 illustrates the alignment of RRFE principles, business objectives, business drivers, and outcome factors.

Table 1

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury -free workplace
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Maintain top quartile reliability relative to transmission peers
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB

3. ECONOMIC ASSUMPTIONS

An economic outlook and customer load forecast are developed and used as basic assumptions in developing the investments. The load forecast is discussed in Exhibit E1, Tab 3, Schedule 1.

The investments reflected in this Application relied on the forecasts of key economic assumptions detailed in this section.

3.1 Transmission Cost Escalation for Construction, Operations and Maintenance

Hydro One used the "Transmission Cost Escalators for Construction, Operations & Maintenance" set out in Table 2 below as a planning tool to forecast expenditure level changes for transmission materials and services. These escalators are a broad average measure of the industry-wide yearly price changes, and track a representative basket of equipment and labour, comprised of the following types of equipment and labour: operation; supervision and engineering; load dispatching; station expenses; lines; meters; customer installations; maintenance; structures; station equipment; overhead lines; underground lines; line transformers; and miscellaneous.

Table 2: Global Insight's November 2015 forecast (%)

	Historical Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Transmission Cost Escalation for Construction	-0.1	2.0	2.2	1.3	1.8	2.3	2.5
Transmission Cost Escalation for Operations & Maintenance	2.1	0.9	0.4	-0.7	0.3	1.3	1.6

3.2 Consumer Price Index

Hydro One's operations are located only in the Province of Ontario. As a result, Hydro One has relied on the consumer price index ("CPI") for Ontario set out in Table 3, published by Statistics Canada, for its assumptions about inflation for other costs. The CPI provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation.

Table 3: Ontario CPI (%)*

	Historical Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
CPI – Ontario	1.4	1.1	2.3	1.3	2.3	2.0	2.0

* Global Insight's February 2015 forecast.

3.3 Exchange Rate (CDN:USD)

The historic rates in Table 4 are the average exchange rates for 2012, 2013 and 2014 from the Bank of Canada. The exchange rate forecasts for 2015 to 2018 are based on the November 2015 edition of the Global Insight Forecast.

Table 4: Exchange Rate (CDN:USD)

Description	Historical Years				Bridge Year	Test Years	
	2012	2013*	2014*	2015	2016	2017	2018
Exchange Rate	1.000	0.971	0.905	0.785	0.762	0.800	0.839

*The actual exchange rates were lower than forecasted due to unexpected decline in oil prices.

4. INVESTMENT CANDIDATE DEVELOPMENT AND SCOPING

As discussed in Exhibit B1, Tab 2, Schedules 2 to 6, throughout the year, Hydro One conducts needs assessments through its customer engagement activities, asset risk analyses, and regional and local supply planning. Using this information, planners identify potential investments that classified as “Sustainment”, “Development”, “Operations”, “Common Corporate”, and “Customer Care” to align with the company’s business activities. Exhibit B1, Tab 2, Schedules 3 to 6 discuss how Sustainment and Development investment candidates are identified. For completeness, this section provides information on how Operations and Common Corporate investment candidates are identified.

4.1 Operations

Operations investments are principally determined by control centre requirements, technology lifecycles and compliance requirements. Hydro One Transmission uses the following principles to define its Operations investment strategy:

- Use commercial-off-the-shelf software products that are best in class in the electrical utility industry;
- Enhance and extend existing applications, fully utilizing the existing tool set;
- Maximize asset utilization factors and useable lifespan;
- Maximize the use of operating data and increase data accuracy, improving business efficiency, safety, and the reporting of performance analysis and assessment of asset investment decisions; and
- Optimally replace and upgrade hardware and software according to industry best practice.

Assessments are conducted to determine the support requirements for existing operating facilities, including control facilities, infrastructure, telecommunications and administrative and engineering tools. Investment needs are prioritized based on compliance requirements and their impact on the electricity system and customers. Capital investments are typically driven by market rules and regulatory requirements and the need to replace end-of-life technology or implement major upgrades for existing operating tools and facilities. Since most technology investments are subject to contractual and interoperability restrictions, alternate solutions and investment pacing options may be limited.

4.2 Common Corporate Investments

In addition to the architectural principles described in Exhibit B1, Tab 3, Schedule 6, IT investment planning is guided by the following principles:

- Leverage enhanced capabilities already inherent in the existing tool set;
- Make better use of existing data;
- Adjust existing processes; and
- Upgrade hardware and software in anticipation of its end-of-life.

IT investments are typically subject to strict contractual limits. As a result, alternatives may be very limited; for example, specific investments must be made to maintain the necessary vendor support for a given IT solution.

Once real estate and facilities investment needs are identified, they are prioritized on the basis of legal requirements, operational requirements, and finally, the condition of the facilities. Where available, alternatives are considered, such as leasing additional or alternate space, making minor capital investments, and repurposing existing facilities. Candidate investment proposals are developed from conceptual plans; further detail is provided in Exhibit B1, Tab 3, Schedule 7.

Vehicles are considered for replacement on the basis of predetermined criteria including, but not limited to: manufacturer's life expectancy, average cost per kilometer, regulated maintenance standards and safety/risk. Replacements are actually recommended if the existing assets cannot continue to meet operating requirements, are no longer safe to operate, or are no longer cost-effective to operate. Further detail is provided in Exhibit B1, Tab 3, Schedule 8.

4.3 Assessment of Risk to Business Objectives and Evaluation Criteria

Hydro One's risk-based investment planning process incorporates a risk definition that is consistent with the International Organization for Standardization (ISO) 31000 - 2009 Standard: "risk" is the effect of uncertainty on objectives. For clarity, in this Exhibit, "risk" refers to the risk of not achieving Hydro One's business objectives.

Once investment candidates are identified, they are assessed based on the value created by mitigating risks or their ability to enhance productivity. These assessments follow a structured process that includes the following key steps: (1) risk/hazard identification; (2) risk analysis and controls assessment; and (3) risk treatment.

4.3.1 Risk/Hazard Identification

The data collected as part of the needs assessment provides insight into potential hazards, vulnerabilities, threats or other risk sources that could present risks to achieving Hydro One's business objectives, such as asset condition, configuration or capacity.

4.3.2 Risk Analysis and Controls Assessment

Based on identified sources of risk, a three-stage risk analysis and controls assessment is conducted:

- an assessment of the worst credible consequence/impact of a given risk on a specific business objective, as measured on a five-point risk tolerance scale from "minor" to "catastrophic";
- an evaluation of the likelihood that a given consequence/impact will materialize, as measured on a six-point likelihood scale, from "unexpected" to "very likely"; and
- an evaluation of the effectiveness of existing controls.

A candidate investment may impact one or more business objectives. An asset investment may score high in the risk analysis because its deteriorated condition presents reliability and customer satisfaction risks stemming from probable equipment failure and a subsequent outage. In the risk analysis, a customer's capacity upgrade request may be rated highly because failing to fulfill it would pose significant risk to customer satisfaction, compliance with the Transmission System Code, and reliability.

The risk assessment process incorporates a probability and consequence-of-outcome "Business Driver Evaluation Matrix", which is illustrated in Figure 3, to determine the impact for each business driver. The risk assessment includes: (a) a baseline risk evaluation, representing the risk of not proceeding with the investment: and (b) a residual risk evaluation, representing the remaining risk after the investment is put into service.

The baseline risk assessment entails defining a credible risk scenario which may occur if an investment is not implemented. The baseline risk analysis involves the identification of the impact of the risk scenario, as measured by the outcome factors. The impact on the outcome factors may result in increased risk to achieving the company's business objectives as illustrated in Figure 2.

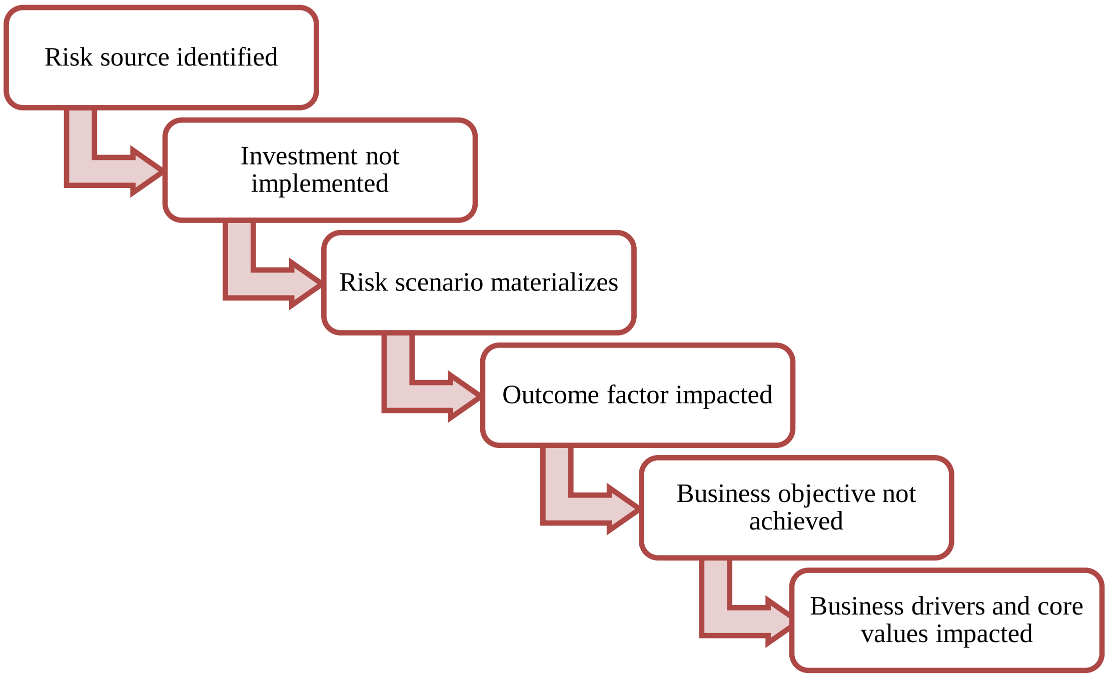


Figure 2: Baseline Risk Assessment Impact

A similar process is followed as part of the residual risk assessment, which identifies the impacts and residual risks following investment implementation. These risks assessments form a clear link between risks and the value of candidate investments.

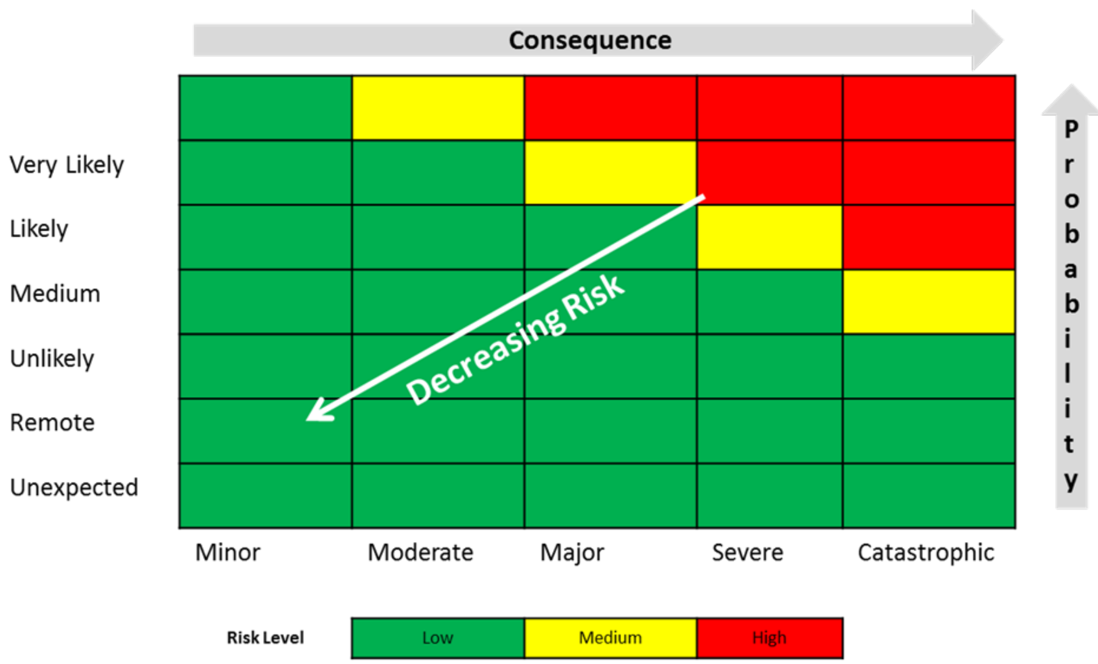


Figure 3: Business Driver Evaluation Matrix

4.4 Risk Treatment and Options Analysis

Following the identification and assessment of a given risk exposure, a decision is made to accept the risk or treat the risk. For risks identified for mitigation, risk treatment options, in the form of investment proposals, may be developed to address the risk. Risk mitigation occurs following investment implementation and may reduce the impact of the consequence or reduce the likelihood of the consequence occurring. The difference between the baseline risk and residual risk is the risk mitigation value created by the investment.

When developing the candidate investment, planners should consider multiple options that reflect different levels of funding, effort and outcomes to address the identified risk and investment need. Figure 4 illustrates the three funding levels (sometimes referred to as “accomplishment levels”) and their corresponding risk levels.

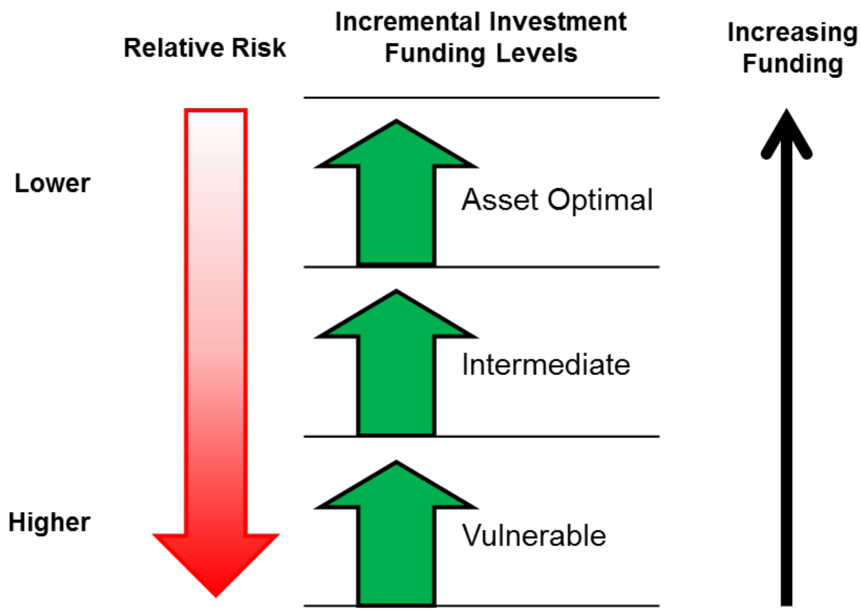


Figure 4: Accomplishment Levels versus Risk

The "vulnerable" investment level meets minimum compliance and health and safety requirements and is tolerable for only brief periods. At this level of funding, asset maintenance and/or replacement needs are not fully met, and asset failure is a possibility. The residual risk at the end of the five year planning period is just outside the "red zone" shown in Figure 3.

At the "intermediate" investment level, asset performance and risk are held at current levels. Where appropriate, there may be several intermediate investment levels to provide appropriate granularity between the "vulnerable" and "asset optimal" alternatives.

The "asset optimal" investment level represents the balancing point where total lifecycle costs of the asset are minimized and risk is low. This level of investment will ensure customer and asset needs are fully met, and there is a high degree of confidence that assets performance will align with the business objectives.

Further, select investments may have "start date flexibility". In these instances, an investment may functionally be allowed to shift during the optimization process by a specified period of time, typically a year or two. However, the risk exposure over the interim period may increase as a result of project deferral, as illustrated in Figure 5. This start date flexibility enables alternative investment pacing scenarios to be considered and assessed.

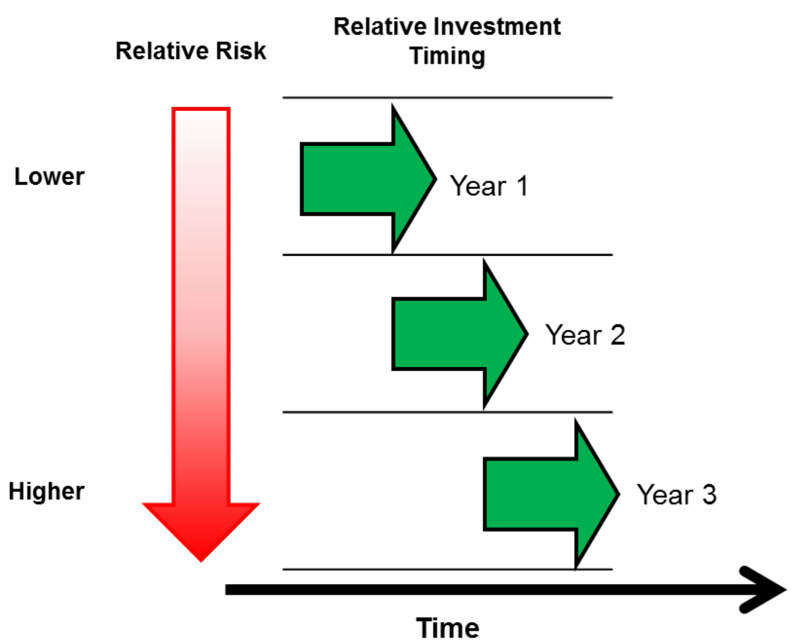


Figure 5: Start Date versus Risk

Across the investment portfolio, the risk assessments are then aggregated for each business driver in order to calculate the overall value of the investment to Hydro One. This overall value of the investment reflects the benefit of the investment through the investment's impact on evaluation criteria, risks mitigated and estimated costs.

These identified options and flexible timing arrangements are, at least in the short term, considered to be viable candidate investments, and are included in the optimization process for potential selection.

4.5 Line of Business Managerial Review

Once the investment plans have been consolidated into an investment portfolio, a structured, multi-level managerial review is conducted. In the AIP tool, investment candidates are routed for review by management of the relevant line of business. Managerial review of an investment is focused on the justification, the reasonableness of risk and investment value assessment, the appropriateness of the considered alternatives and recommended expenditure profiles, and the proposed investment schedule. If accepted, the candidate investment is included in the optimization process. Managers may reject an investment and send it back to the planner for edits and revisions. Multiple layers of review enable internal and cross-functional reviews and notional agreement on an investment candidate prior to its inclusion in the investment plan.

5. PRIORITIZATION AND RISK OPTIMIZATION: THE INVESTMENT PLAN PROPOSAL

All candidate investments (including alternatives) are then aggregated into a consolidated investment portfolio for optimization as illustrated in Figure 6. This investment optimization process occurs annually. The output of the process is a draft investment plan comprised of both capital and OM&A investments

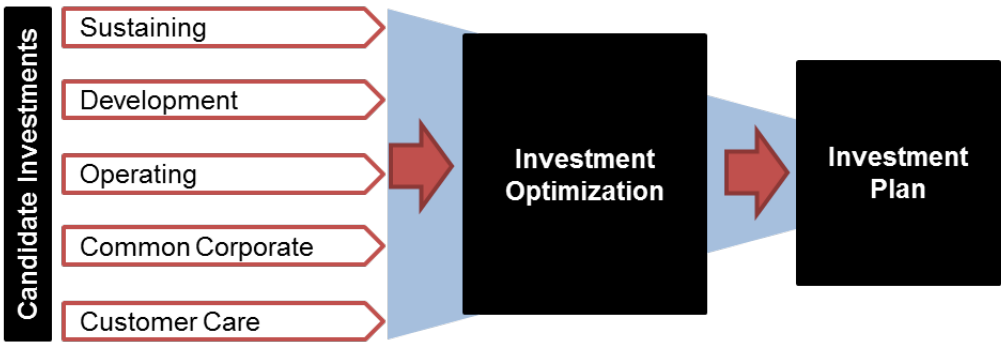


Figure 6: Candidate Investment Aggregation

At the core of the optimization process is the multi-variable framework based on the business drivers in Table 1, which helps decision-makers understand and quantify business risks and uncertainties so that objective decisions can be made, respecting investment priorities.

The optimization process attempts to find the combination of investment options and alternative start dates that maximizes investment value without exceeding the constraints that have been defined. This iterative process is intended to produce a portfolio of appropriately paced investments that achieves an optimal balance between cost effectiveness, timely responsiveness to customer needs, asset requirements and business needs.

5.1 Operational Stakeholder Engagement & Executive Approval

After the investment plan is optimized, cross-functional operational review meetings are held to review and discuss the draft investment plan. This review is meant to facilitate the consideration of additional operational and execution considerations such as resourcing and material and outage availability. Based on these discussions, adjustments may be made to reflect emerging execution risks and financial considerations. The end product is a revised investment plan proposal that represents an effective balance between these considerations.

Once the corporate support costs described in Exhibit C1, Tab 3, Schedules 3 and 4 are layered onto the investment plan, the end product is reviewed for approval by the executive team.

6. INDIVIDUAL INVESTMENT APPROVAL AND IMPLEMENTATION

Once the overall plan is approved, individual project proposals not already in execution are developed further for project-specific approvals. Factors considered in the assessment process include:

- the need for the investment;
- the implications of not doing the work and possible risk;
- the anticipated benefits (e.g., customer delivery point performance);
- the recommended solution; and
- estimated costs and in-service timing.

In determining the recommended solution, alternative approaches and project risks are considered. The proposals are then reviewed in a series of steps at the senior management and executive levels, depending on the dollar limit and the significance of the investment. The proposals are then approved, consistent with the provisions of the expenditure authority register, described in Exhibit A, Tab 5, Schedule 2.

6.1 Monitoring & Control

On a monthly basis, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures. Variances from plan are identified and corrective action is taken. In the event that spending on a project is expected to be materially different from the amount originally approved, an interim review of variance ("IROV") is prepared. In effect, an IROV is an amended business case that is reviewed and approved based on the revised set of circumstances (such as revised cost, scope and/or schedule). The IROV is approved in accordance with the limits set out in the expenditure authority register. Projects that cannot be re-justified are reprioritized, cancelled or otherwise adjusted.

6.2 Re-direction of Funds

While the investment plan is the product of extensive planning and analysis, implementation of the plan must be done in a manner that is dynamic and flexible. Re-direction of approved funds may be required as new risks or opportunities emerge, including:

- changing customer needs and requirements (e.g., new regional plans, unexpected load growth, etc.);
- changing asset priorities based on new information;
- changing external requirements (such as changing industry, regulatory, technical standards and new policy initiatives); and
- major unforeseen events (e.g., extensive storms and equipment failures).

The re-direction of funds allows appropriate and prudent adjustments to be made to the work originally identified in the investment plan. As an example, the emergency restoration work needed to repair equipment failures or storm damage to a transmission line can be significant. Such events may necessitate the re-direction of funds and field resources from other investment areas.

SUMMARY OF CAPITAL EXPENDITURES

1. INTRODUCTION

This Exhibit provides an overview of the capital investments reflected in the investment plan. Investment summary documents describing capital projects or programs with cash flows in excess of $3.0 million in either 2017 or 2018 are filed at Exhibit B1, Tab 3, Schedule 11.

Table 1 provides a summary of Hydro One Transmission's capital expenditures for each investment category over the period 2012 to 2021.

Table 1: Summary of Transmission Capital Budget ($ Million)
Including Capitalized Overheads and Interest Capitalized*

Description	2012	2013	2014	Historic 2015	Bridge 2016	Test 2017	Test 2018	Forecast 2019	2020	2021
Sustaining	389.3	480.0	621.3	694.3	724.3	776.8	842.1	825.7	915.2	1118.1
Development	329.4	171.7	131.6	166.0	166.0	196.4	170.2	244.0	254.0	258.3
Operations	15.2	17.7	28.4	15.6	30.1	25.4	30.8	58.8	21.1	24.7
Common Corporate Costs Capital	42.1	49.1	63.4	67.1	83.5	77.6	79.1	79.1	78.2	73.8
Total	**776.0**	**718.5**	**844.6**	**943.0**	**1003.9**	**1076.1**	**1122.2**	**1207.5**	**1268.6**	**1474.9**

*Includes Allowed Funds Used During Construction.

The treatment of capital contributions and additions and deductions to construction work in progress are discussed in Exhibit B1, Tab 3, Schedule 3 and Exhibit D2, Tab 2, Schedule 3.

2. TREND ANALYSIS

The capital investments in the test and forecast years are intended to achieve Hydro One Transmission's business objectives of:

- maintaining top quartile reliability by mitigating risk arising from asset deterioration;
- minimizing the long-term costs of maintaining the reliability of the transmission system;
- ensuring that compliance with the regulatory and reliability standards is maintained:
- improving current levels of customer satisfaction;
- driving towards an injury-free workplace: and
- sustainably managing the environmental footprint of operations.

The proposed level of investment will also maximize the life of assets to avoid unnecessary capital expenditures.

With its investment plan, Hydro One continues to strike a careful balance between: (a) developing the transmission system and building new infrastructure; (b) sustaining existing assets and maintaining the health of the system; and (c) rate impacts. Between 2009 and 2012, Hydro One invested significantly in Development capital to comply with government policies related to the connection and integration of renewable energy generation and the retirement of coal-fired generation. Since then, system development needs have declined while system renewal needs have increased, posing a risk to current reliability levels. (See section 2.1 of this Exhibit for further discussion.)

Customer feedback and external benchmarking evidence both support increased capital spending above historical levels to address this risk. As discussed in Exhibit B1, Tab 2, Schedule 2 and Attachment 1 to that Exhibit, customers do not want any deterioration in current service levels, and customers believe that Hydro One should be proactive in addressing current and emerging risks to reliability now. Hydro One also commissioned a transmission total cost benchmarking study, which concluded that Hydro One Transmission's historical capital spending levels were significantly below median in its peer group. (This study is provided in Exhibit B2, Tab 2, Schedule 1.)

In finalizing its investment plan, Hydro One used the total cost benchmarking study as a reference tool to further validate the proposed increases in spending. Based on the results of the report and Hydro One's investment proposal, the 2017 and 2018 total expenditures (capital and OM&A) will still remain at or below median levels relative to the company's peer group.

2.1 Sustainment Capital

Sustainment capital spending is increasing to address safety, customer and reliability needs, while doing so in a cost effective manner.

As described in Exhibit B1, Tab 2, Schedule 4, Hydro One has modified its asset management approach to include reliability risk as a leading indicator of future transmission system performance. Hydro One's approach has been informed by the development of this approach in other jurisdictions. Reliability risk is used by Hydro One in its asset management process to gauge the impact of its investments on future transmission system reliability. It also provides a directional indicator to inform the appropriate level and pacing of sustainment capital. It is not used to identify specific asset needs and investments. With this direction, using its asset performance and condition analyses, Hydro One has developed a Sustainment capital plan that prioritizes the replacement of assets with a goal to maintain top quartile reliability and reduce reliability risk. After focusing on stations investment in recent years, beginning in 2018, the plan places a greater emphasis on lines-related investments while maintaining stations spending at a prudent level.

Hydro One Transmission's approximately 30,000 kilometres of transmission lines throughout the province require increased levels of refurbishment to ensure that electricity continues to be delivered in the safe, reliable manner that Hydro One's customers expect. The insulator replacement program is necessary to remove and replace faulty insulators for public safety reasons. Stations and related equipment continue to require refurbishment to address deteriorating asset conditions. Wherever possible, Hydro One looks for opportunities to extend the life of its assets in order to provide value to its customers. For example, Hydro One is increasing its zinc coating program for steel transmission towers in high corrosion areas, in an effort to maximize the life of its 52,000 towers and avoid costly replacements.

Hydro One anticipates that its work program will face outage constraints caused by the planned nuclear refurbishments at Darlington and Bruce in 2021 and beyond and the planned closure of Pickering generating station in 2025. Accordingly, Hydro One has paced Sustainment work over the next five years to ensure that assets are in-service before such constraints make work more difficult to complete. Beginning in 2017, Hydro One intends to replace deteriorating assets, before the next bow wave of Sustainment requirements surfaces in 2030, as explained in Exhibit B1, Tab 2, Schedule 4.

2.2 Development Capital

The Development capital expenditures are primarily driven by inter-area network transfer, local area supply, and load connection projects identified through regional planning. These projects include the Supply to Essex County Transmission Reinforcement in the Windsor-Essex area, and capacity increase at Lisgar TS in the

Greater Ottawa area. Details of the expenditures under this program are provided in Exhibit B1, Tab 3, Schedule 3.

The forecast level of Development expenditures for the future years, 2019 to 2021, is expected to increase beyond the planned level of expenditure in the test years. This is mainly due to major inter-area network projects, such as the East-West Tie Expansion and the Milton SS Station Expansion, which will be in significant construction phases and forecasted to be placed in service in 2020 and beyond.

2.3 Operations Capital

The overall spending level for 2016-2019 is higher than in historical years. The increase is attributed to the building of a new back-up control centre and the end-of-life replacement of grid control network elements that are required to monitor and control the transmission system. Details of the expenditures under this program are provided in Exhibit B1, Tab 3, Schedule 4.

2.4 Common Corporate Capital

Common Corporate capital spending levels in the test years are forecast to be higher than historical levels due to: (a) higher capital spending on information technology development projects, which aim to improve productivity in Hydro One’s operations; (b) increased facility needs for expanding Sustainment, Development and Operations work programs; and (c) incremental capital investments in transport and work equipment, primarily, a new helicopter. The capital spending levels are forecast to be relatively stable through the test years.

COMPARISON OF NET CAPITAL EXPENDITURES BY MAJOR CATEGORY– HISTORIC, BRIDGE AND TEST YEARS

Transmission Capital ($millions)	2012	2013	2014	2015	2016	2017	2018
Sustaining Capital							
Transmission Stations							
Circuit Breakers	11.2	23.4	25	7.1	2.4	1.1	0
Power Transformers	78.4	87	111.1	43.5	8.9	0	0
Other Power Equipment	28.3	26.5	27.5	12.5	4.5	0	0
Ancillary Systems	16.4	15.6	22	17.1	5.2	1.3	0
Station Environment	7.6	6.6	10.5	3.8	1.3	0	0
Integrated Station Investments	62.1	89	157.3	374.2	454.4	457.8	404.7
Tx Transformers Demand and Spares	0	0	0	27.2	20.5	25.3	25.8
Protection and Automation	95	84.4	97.9	60.2	45.6	45.2	59.1
Site Facilities and Infrastructure	23.4	22.9	30	20.3	9.4	6.7	6.7
Total Transmission Stations Capital	**322.5**	**355.3**	**481.3**	**565.8**	**552.2**	**537.5**	**496.2**
Transmission Lines							
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	65.3	92	119.4	125	170.7	237	323.4
Underground Cables Refurbishment and Replacement	1.6	32.8	20.6	3.5	1.4	2.3	22.5
Total Transmission Lines Capital	**66.8**	**124.8**	**140**	**128.4**	**172.2**	**239.3**	**345.9**
Total Sustaining Capital	**389.3**	**480.0**	**621.3**	**694.3**	**724.3**	**776.8**	**842.1**

1

Development Capital	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Inter Area Network Transfer Capability	117.8	41.7	45.9	86.3	93.9	79.8	59.8
Local Area Supply Adequacy	86.4	54.0	49.1	64.9	48.2	43.8	45.7
Load Customer Connection	60.6	24.7	14.6	7.7	16.0	58.1	57.4
Generator Customer Connection	-0.2	-0.3	1.7	-1.7	-1.2	0.0	0.0
P&C Enablement for Distributed Generation	2.5	1.2	1.2	2.1	1.4	0.0	0.0
Risk Mitigation	17.7	27.5	17.0	3.1	2.1	12.6	5.2
Power Quality	0.0	0.0	0.0	0.0	2.1	2.1	2.1
TS Upgrades to Facilities Distribution Generation	33.1	13.9	-1.0	-1.2	0.0	0.0	0.0
Performance Enhancement	0.7	0.1	0.5	1.3	0.3	0.0	0.0
Smart Grid	10.7	8.8	2.5	3.5	3.1	0.0	0.0
Total Development Capital	**329.4**	**171.7**	**131.6**	**166.0**	**166.0**	**196.4**	**170.2**

Operations Capital							
Grid Operating and Control Facilities	3.4	11.3	23.3	14.2	18.7	11.4	19.3
Operating Infrastructure	11.9	6.4	5.1	1.4	11.4	14.0	11.5
Total Operations Capital	**15.2**	**17.7**	**28.4**	**15.6**	**30.1**	**25.4**	**30.8**

2

Capital Common Corporate Costs and Other Costs							
Transport and Work, and Service Equipment	14.6	18.8	22.0	22.1	26.1	24.1	25.0
Information Technology (including Cornerstone)	30.5	22.9	26.8	21.6	33.6	31.4	28.1
Facilities & Real Estate	11.6	7.4	13.7	22.7	22.6	18.4	20.9
Other (including CDM)	-14.7	0.0	0.9	0.7	1.2	3.7	5.1
Total Capital Common Corporate Costs and Other Costs	**42.1**	**49.1**	**63.4**	**67.1**	**83.5**	**77.6**	**79.1**
Total Transmission Capital	**776.0**	**718.5**	**844.6**	**943.0**	**1003.8**	**1076.1**	**1122.2**

SUSTAINING CAPITAL

1. INTRODUCTION

The sustaining capital expenditures described in this exhibit are required for Hydro One to meet the business objectives, (found in Exhibit B1, Tab 1, Schedule 2), including mitigating reliability risk and maintaining first quartile reliability in a safe manner to its customers. Decisions are also made to ensure compliance with regulatory, environmental and reliability standards. Employee safety concerns are also an important part of the decision making process as Hydro One drives towards an injury free workplace. Where feasible, asset life is extended to avoid larger capital replacement through maintenance programs.

The expenditures outlined in this section were determined to be necessary by the processes described in the Transmission System Plan provided with this application and based on the assessment of the assets and system needs described in the Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6.

Hydro One manages its Sustaining Capital program by dividing the expenditures into two major categories:

- Stations: the work required to refurbish or replace existing assets located within transmission stations, including existing protection, control, and telecommunication assets, and

- Lines: the work required to refurbish or replace existing assets associated with overhead and underground transmission lines.

Throughout this exhibit the term “end of life” or (“EOL”) is used. It is defined as “the likelihood of failure, or loss of an asset’s ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences.”

The term ‘expected service life’ or (“ESL”) is also used throughout this exhibit, which has been defined as “the average time in years that an asset can be expected to operate under normal system conditions.”

2. SUSTAINING CAPITAL SUMMARY

The required funding for Sustaining Capital in the test years, along with the spending levels for the bridge and historic years, is provided in Table 1 for each of the major sustaining categories.

Table 1: Sustaining Capital ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Stations	322.5	355.3	481.3	565.8	552.2	537.5	496.2
Lines	66.8	124.8	140.0	128.4	172.2	239.3	345.9
Total	**389.3**	**480.0**	**621.3**	**694.3**	**724.3**	**776.8**	**842.1**

The overall Sustaining Capital requirements for the test year 2017 have increased by 7 % over projected spending in the bridge year 2016. The Sustaining Capital requirements for 2018 are approximately 8% higher than the 2017 requirements. The proposed expenditures in 2017 and 2018 are required to enable Hydro One to maintain system reliability, mitigate reliability risk, ensure compliance with regulatory, environmental and reliability standards and meet safety needs. During the test years, increases in expenditures are attributable to the Lines category, with increased spending required to refurbish deteriorated conductors, apply new zinc protective coating to steel towers, and address safety concerns related to transmission line insulators. The assessments of the assets to be replaced are provided in detail in the Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6.

In the test years spending is increasingly focused on integrated projects in both the Stations and Lines categories. The asset assessments provided in the Asset Needs Overview exhibit determine the assets to be replaced and, where possible, Hydro One has bundled these individual projects into integrated, larger scale Station or Line refurbishment projects. The integrated capital planning approach is described further below. For projects and programs that exceed $3M of spending in either test year, an Investment Summary Document has been provided in Exhibit B1, Tab 3, Schedule 11.

A reduction in the Sustaining Capital would have a number of impacts, including:

- a reduction in reliability at transmission stations, as a result of increased transformer failures, inoperable breakers and switches, and potential mis-operation of protection systems;
- risk of non-compliance with Ministry of Environment and Climate Change regulations relating to oil storage and handling, oil spill containment systems, noise levels, and slow the progress associated with PCB phase out schedules mandated by Environment Canada;
- potential for widespread power disruptions, should the critical protection and control systems start to fail due to slow response to deteriorating conditions;
- risk of non-compliance with NPCC and NERC standards that require secure facilities for connection to the northeast power grid. Protection and control systems are critical in this regard and if compliance cannot be maintained, Hydro One risks citations and fines;

- an increase in power outages attributable to lines facilities, due to failure of conductor, structures, insulators and other components that make up the lines system; and
- risk to public safety as many assets are located in public areas and their failure could lead to significant public safety concerns.

3. INTEGRATED CAPITAL PLANNING

3.1 Introduction

Adopting an integrated capital planning approach allows for a holistic assessment and creation of a plan to improve the entire station, instead of replacing individual components. This process includes assessing individual assets, as well as overall station reliability, maintainability and operability for meeting current customer requirements. This also enables the successful delivery of the work program in an efficient manner, minimizes customer impact by requiring fewer planned outages, and optimizes design, execution and operating efficiency.

Historically, Hydro One has sustained its infrastructure on an individual asset basis. Under an asset-centric approach, and given the deteriorated asset condition of several assets at the same station, several visits to the same station would be required for work programs in a relatively short period of time. This results in multiple planned outages, increasing the risk of customer interruption and reduced reliability.

The focus on individual asset replacement also did not provide an opportunity for a complete assessment of a station. Through the integrated capital planning, the entire station is assessed and connected customers are engaged. This process facilitates the discussion and review of customer concerns and future needs, while assessing operational or reliability risks that can be mitigated or eliminated and efficiencies achieved through reconfiguration and where possible, asset reduction.

3.2 Fundamentals of Integrated Investments

The integrated capital planning process begins with identifying a need for major equipment replacement, such as a transformer or circuit breaker, at a specific station. The station is then assessed as a whole to determine the asset replacement or refurbishment requirements needed within a three year window, for one integrated investment.

The three year window aligns with the typical three to five year project execution duration required for scope development, design, construction and commissioning of integrated investments projects. This approach minimizes the potential for repeated mobilization of work crews to replace individual assets. Assets that are not in need of replacement or refurbishment are maintained until the next investment cycle when they are reassessed.

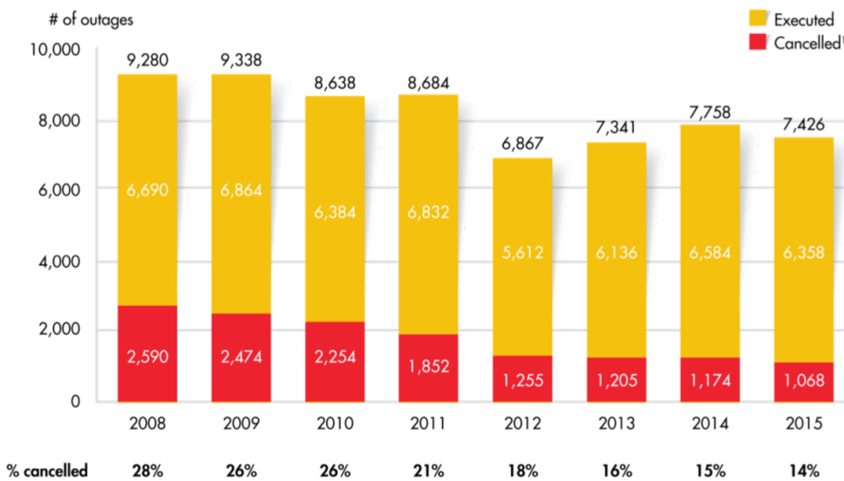
This approach provides opportunities to reduce the number of assets through reconfiguration, utilize modern technology and implement safety by design, to improve reliability, safety and productivity.

3.3 Benefits from Integrated Capital Investments

- Execution Excellence - The station integrated capital investment approach integrates and addresses all major station asset operational risks with one investment which allows for efficiency during design, construction and commissioning. Historically, the asset-centric investment approach has resulted in sustainment capital work execution at up to 75% of Hydro One’s stations annually. In many cases this results in multiple deployments to the same station year over year to accomplish a number of sustainment capital asset replacements.

- Safe Workplace – Evaluating holistic station refurbishment options, as opposed to the individual component replacements within a station, provides greater opportunities to incorporate the principles of safety by design, operability, constructability and maintainability into the integrated solution.

- Customer Benefits – Planning of integrated investments provides opportunity to optimize the solution through customer engagement. In addition, customer impact can be minimized by reducing the number of planned outages during execution, respecting customer constraints and minimizing reliability risk. As illustrated in Figure 1 below, despite increases in sustaining capital expenditures in previous years, Hydro One has been successful in its project coordination and has reduced the number of planned outages per year as well as the number of cancelled outages.



1. Actual number of canceled outages may be lower in reality; some canceled outages are for work no longer required

Figure 1: Number of Outages Per Year

- Cost Avoidance – An integrated capital investment approach enables the system to be reconfigured and standardized, thereby reducing the number of assets within the system. For example, in the 2017 and 2018 test years, Hydro One plans to eliminate 10 transformers and 24 breakers from the system through reconfiguration. This results in avoided capital expenditures of $57 million during the test years.

- Operation & Maintenance Cost Reduction – The reduction of assets through the reconfiguration and standardization of design described above results in less equipment to maintain in the system, reducing maintenance expenses. For example the transformers and breakers eliminated in the test years will result in savings of approximately $2 million in operating and maintenance expenses that would have been required over the life of the assets.

- Environmental – A holistic approach to assessing stations allows for the opportunity to consider environmental concerns through better design and address outstanding station risks identified through asset event investigations, such as appropriate spill containment, and ensure compliance with all environmental regulations.

4. STATIONS

Transmission station facilities are used for the delivery of power, voltage transformation, and switching. They serve as connection points for both load customers and generators. Station facilities contain many components, including: power transformers, circuit breakers, disconnect switches, bus work, insulators, potheads, power cables, surge arrestors, capacitor banks, reactors, instrument devices, protection and control systems, telecommunications facilities, station service systems, grounding systems, site infrastructure and buildings. Stations Sustaining Capital funding covers expenditures required to sustain these assets and other ancillary equipment.

Hydro One has historically divided the Stations Sustaining Capital program into eight asset-centric categories to replace assets on a like-for-like basis. With the need for increased investment to sustain the large asset base, including stations with multiple deteriorating components, Hydro One has adopted the integrated capital planning approach described in section 3.0 above.

Station related projects are now organized in the following four categories:

1. Integrated Stations Investments: the capital investments to refurbish or replace several station components or systems in an integrated manner.

2. Transmission Station Demand & Spares: emergency failure or demand capital equipment replacements of transformers, circuit breakers and other ancillary equipment. This program also covers the purchase of mobile transformers to facilitate planned outages and long lead time strategic spare transformers, breakers and bushings that are required as emergency or operational spares in case of equipment failure.

3. Protection and Automation, capital investments to refurbish or replace selected protection, control, monitoring, cyber security and power system telecommunications equipment not covered under the integrated investments.

4. Site Facilities and Infrastructure: building renovations and modifications, heating, ventilation and air conditioning (HVAC) replacements, roof replacements and water supply enhancements.

Required funding for the test years 2017 and 2018, along with the spending levels for the bridge and historic years are provided in Table 2 for each of these categories.

Table 2: Stations Sustaining Capital ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Circuit Breakers	11.2	23.4	25.0	7.1	2.4	1.1	0.0
Power Transformers	78.4	87.0	111.1	43.5	8.9	0.0	0.0
Other Power Equipment	28.3	26.5	27.5	12.5	4.5	0.0	0.0
Ancillary Systems	16.4	15.6	22.0	17.1	5.2	1.3	0.0
Station Environment	7.6	6.6	10.5	3.8	1.3	0.0	0.0
Integrated Station Investments	62.1	89.0	157.3	374.2	454.4	457.8	404.7
Transmission Transformer Demand and Spares	0.0	0.0	0.0	27.2	20.5	25.3	25.8
Protection and Automation	95.0	84.4	97.9	60.2	45.6	45.2	59.1
Site Facilities and Infrastructure	23.4	22.9	30.0	20.3	9.4	6.7	6.7
Total	**322.5**	**355.3**	**481.3**	**565.8**	**552.2**	**537.5**	**496.2**

The overall stations sustaining capital expenditures for the test year 2017 are approximately 2.7% less than the projected spending in 2016. The spending requirements for 2018 are also approximately 7.7% less than 2017 requirements. These expenditures reflect the asset needs and strategies detailed in the Asset Needs Overview, found in Exhibit B1, Tab 2, Schedule 6, which will meet customer needs and preferences, maintain Hydro One's position in top quarter reliability among its transmission peers, and manage the business in an environmentally responsible manner. The variability observed year over year is directly associated with the timing of specific projects. These modest decreases in Station spending reflect the successful improvement of many stations as a result of completed projects eliminating some of riskiest stations and an increased need to refurbish Lines and associated assets.

4.1 Integrated Station Investments

4.1.1 Introduction

As noted in Section 3.0 above, efficiency gains are achieved in many cases by replacing all end of life (EOL) components within the station as part of the same project. This practice also contributes to increased customer satisfaction due to fewer planned outages, and reduced risk of customer interruptions that can occur when one or more system elements are removed from service. Small amounts of spending will continue in legacy asset-centric programs in 2016 and 2017 to complete projects already planned and in execution.

The initial wave of integrated investments was planned and executed as Integrated Station Re-Investment and Integrated Station Component Replacement investments as filed in EB-2014-0140. In late 2014, the concept of integrated investment matured and evolved into the primary planning approach for Stations Sustaining Capital investments.

4.1.2 Investment Plan

Integrated Station Investments are organized by grouping projects into similar types of work. Table 3 outlines the proposed funding for test years 2017 and 2018, along with the spending levels for the bridge and historic years for each grouping.

Table 3: Integrated Station Investment Projects ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Air Blast Circuit Breaker Replacement Projects	22.4	17.9	28.0	80.5	95.9	95.1	109.4
Station Reinvestment	27.0	39.7	31.1	61.5	61.4	101.5	109.5
Integrated Station Component Replacements	(3.3)	30.6	97.7	229.2	297.1	261.3	185.7
Other Historical Projects	16.0	0.8	0.5	3.0	0.0	0.0	0.0
Total	**62.1**	**89.0**	**157.3**	**374.2**	**454.4**	**457.8**	**404.7**

Air Blast Circuit Breaker (ABCB) Replacement Projects

Air blast circuit breakers are the poorest performing breakers in the Hydro One transmission system. Typically ABCBs were originally installed at critical transmission stations during the 1970s build of the transmission system. ABCBs have the highest operating cost of any breaker technology, due to their high pressure air systems with sensitive components that need frequent specialized maintenance. These circuit breakers are no longer manufactured and many models lack support for parts and technical expertise. For more information on asset assessments on ABCB and the need for replacement see Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6.

The transmission stations identified for ABCB replacements are outlined in Table 4. These breakers planned for replacement have been problematic and are in need of replacement due to performance, obsolescence, and system criticality. The work includes replacement of the existing ABCB's with modern SF6 circuit breakers, and the replacement of protection, control, telecom and ancillary station equipment. These investments include necessary reconfiguration or station upgrades to meet current system requirements, improve operational effectiveness and overall system performance.

Table 4: Air Blast Circuit Breaker Replacement Projects ($ Millions)

Ref#	Description	Test Years		Total Project Cost
		2017	**2018**	
S01	Beck #1 SS	5.9	12.0	24.1
S02	Beck #2 TS	29.8	14.9	90.7
S03	Bruce A TS	13.8	19.7	104.9
S04	Bruce B SS	0.9	24.6	65.2
S05	Cherrywood TS	1.4	3.8	60.6
S06	Lennox TS	26.1	16.9	83.7
S07	Richview TS	16.9	13.5	95.5
	Other Projects <$3M	0.2	4.1	
	Total	**95.1**	**109.4**	

Additional details for these projects are provided in the Investment Summary Documents S01 to S07 in Exhibit B1, Tab 3, Schedule 11.

Station Reinvestment Projects

Consistent with the strategy of integrated investments, station reinvestment projects address many assets that are in need of replacement at a single station, including functional reconfiguration. These projects stem from replacement needs identified during the asset assessment process, the details of which are available in the Asset Needs Overview, found in Exhibit B1, Tab 2, Section 6, with further details available on a project basis in the Investment Summary Documents noted below. The integrated solutions employed also allow for station reconfiguration, if required, to meet current customer requirements or current Hydro One design standards that often result in asset reduction and design standardization. Synergies in design, construction and procurement can be best realized by executing an integrated project of this nature when all major station infrastructure is in need of replacement within the same general timeframe.

This category was previously referred to as End of Life Station Reconfigurations in filing EB-2014-0140. The transmission stations identified for station reinvestment are outlined in Table 5. The work will entail replacement of end of life assets as well as a substantial reconfiguration to the station's topology to meet current system requirements, such as deteriorating condition, or customer needs.

Table 5: Station Reinvestment Projects ($ Millions)

Ref #	Description	Test Years		Total Project Cost
		2017	2018	
S08	Beach TS	16.5	15.9	76.5
S09	Centralia TS	12.5	6.2	20.7
S10	Dryden TS	16.2	0.1	31.0
S11	Elgin TS	22.6	17.8	58.2
S12	Espanola TS	3.0	0.0	24.9
S13	Gage TS	1.2	12.4	36.0
S14	Kenilworth TS	5.6	11.2	18.6
S15	Nelson TS	2.1	20.2	22.5
S16	Palmerston TS	8.8	11.6	25.1
S17	Wanstead TS	11.7	13.0	28.5
	Other Projects < $3M	1.4	1.0	
	Total	**101.5**	**109.5**	

Additional details for these projects are provided in the Investment Summary Document S08 to S17 found in Exhibit B1, Tab 3, Schedule 11.

Integrated Station Component Replacement Projects

Projects within this grouping address multiple components such as transformers, spill containment, protection, and control systems, circuit breakers, disconnect switches, surge arresters and other station ancillary systems, at a station in an integrated manner, without altering the functional and electrical configuration. Need for replacement of these assets is determined through the asset assessments provided in Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6. Typically, component replacement projects are needed as a result of condition, obsolescence, performance, environment, safety, and customer requirements. The scope of identified work does not warrant a major rebuild or reconfiguration of the station. This category of Sustaining Capital expenditure was created in 2013 on a pilot basis for nine transmission stations with work spanning the 2013 to 2016 period. The intent of the pilot was to work through a modified approach to planning and executing component replacement work to leverage efficiencies through better integration.

This category captures the Metalclad Switchgear Replacements, Integrated DESN Replacements and Integrated Station Component Replacements categories identified in filing EB-2014-0140.

The transmission stations identified for integrated station component replacement are outlined in Table 6. The work will entail replacement of multiple assets to address operational risks in an integrated manner.

Table 6: Integrated Station Component Replacement Projects ($ Millions)

Ref #	Description	Test Years		Total Project Cost
		2017	2018	
S18	Alexander SS	14.4	8.8	24.0
S19	Allanburg TS	4.7	1.0	32.8
S20	Aylmer TS	3.5	0.0	23.4
S21	Barrett Chute SS	9.3	3.9	17.7
S22	Birch TS	12.1	13.8	30.5
S23	Bronte TS	3.7	17.1	33.1
S24	Bridgman TS	0.2	3.3	39.9
S25	Buchanan TS	4.2	0.0	29.7
S26	Cecil TS	9.4	0.0	12.0
S27	Chenaux TS	7.5	2.1	19.5
S28	Crawford TS	4.2	0.0	8.4
S29	DeCew Falls SS	4.9	0.0	12.6
S30	Dufferin TS	6.5	7.4	21.7
S31	Ear Falls TS	10.9	0.0	18.3
S32	Frontenac TS	3.8	1.5	9.5
S33	Hanmer TS	24.5	11.0	63.5
S34	Hawthorne TS	1.6	4.3	27.0

S35	Horning TS	14.3	14.9	36.6
S36	Leaside TS Bulk	5.9	5.6	31.1
S37	Leaside TS 27.6 kV	6.3	6.5	21.1
S38	Main TS	5.4	8.4	24.8
S39	Manby TS	3.1	1.8	8.8
S40	Martindale TS	18.6	18.6	64.7
S41	Minden TS	4.2	7.0	17.2
S42	Mohawk TS	4.6	4.7	13.9
S43	N.R.C. TS	7.1	0.7	30.8
S44	Pine Portage SS	1.9	5.9	18.3
S45	Richview TS	7.3	0.0	25.1
S46	Sheppard TS	9.8	9.3	28.1
S47	St. Isidore TS	9.1	0.0	26.1
S48	Stanley TS	0.5	6.1	24.5
S49	Strachan TS	5.1	2.8	8.4
S50	Strathroy TS	5.3	0.0	17.3
	Other Projects < $3M	27.4	19.3	
	Total	**261.3**	**185.7**	

Additional details for these projects are provided in the Investment Summary Document S18 to S50 in Exhibit B1, Tab 3, Schedule 11.

4.1.3 Summary of Expenditures

The planned Integrated Station Investments expenditures for 2017 and 2018 are $457.8 million and $404.7 million respectively. Expenditures in Integrated Station Investments are highly dependent on the type and magnitude of individual projects. Many projects are driven by similar needs such as the need to replace air blast circuit breakers or transformers. The scope of each project is explained in full with individual rationales provided in the Investment Summary Documents in Exhibit B1, Tab 3, Schedule 11. In general, Hydro One's fleet of stations has deteriorated to the point of requiring significant investment to maintain and operate a safe and reliable transmission system.

A reduction in this program will result in an increase in the length of time required to address degrading performance of air blast circuit breakers at critical network stations, and the integrated rebuild of these stations delivering load to customers. Negative impacts to both system and customer reliability would be a result.

4.2 Transmission Station Demand and Spares

4.2.1 Introduction

Hydro One strives to maximize the useful asset life of all stations equipment and to prudently refurbish or replace assets as required to ensure that assets remain in good working order and maintain a safe and reliable transmission system. However, equipment failures can occur and must be addressed quickly to minimize customer impacts and reduce the risk to overall system reliability. Hydro One plans for reactive maintenance or asset replacements to address equipment failures. Hydro One therefore maintains a sufficient level of spare power equipment to ensure that failed equipment can be replaced and return the system to normal operating conditions quickly and efficiently.

4.2.2 Spare Transformers

Hydro One’s transmission system was developed over a time span exceeding 100 years. The evolution of design standards and operating principles over time, coupled with construction and material availability constraints have led to the deployment of a mixture of various types of asset within an asset class.

The diversity of the assets within Hydro One’s system is the key factor in establishing spare equipment requirements. The primary objective is to ensure that Hydro One has the ability to recover from major power equipment catastrophic failure events and restore supply reliability in a timely and safe manner. As such, the minimum level of spare transformers is correlated to the types of transformers deployed in Hydro One's system. In 2009 Hydro One consolidated 30 types of transformers to 14 standards. These 14 standards include mid-size (15 to 42 MVA ratings) and large-size transformers (greater than 42 MVA ratings), and auto-transformers (larger than 125MVA).

Over time, as Hydro One rebuilds and replaces deteriorating assets, focus will be placed on ensuring that a high degree of standardization is adhered to. In 2009, approximately 80% of Hydro One's transformer fleet were standard units. In 2016, 84% of Hydro One's transformers are standard units, while 16% are non-standard transformers. It is anticipated that over the next 15 years, standardization will trend toward 90%.

Spare transformer requirements will decline as Hydro One continues to achieve higher levels of standardization. Today, inventory includes 48 operating spare transformers; 36 of these are standard units and 12 are non-standard.

While Hydro One has taken steps to institute standardization, adequate inventory to address the failure of non-standard transformers must continue until station reinvestment and new customer requirements allow for transformer standardization across Hydro One's entire fleet.

4.2.3 Investment Plan

This program funds the demand replacement of transmission system assets, resulting from unplanned or premature equipment failure, as well as the procurement of operating spare equipment, including power transformers and circuit breakers. This program ensures that a sufficient level of inventory of critical and ancillary power equipment is available as operational spares or for emergency replacement in the event of equipment failure.

The purchase of operating spare transformers is in line with Hydro One's probabilistic approach to determine the number of spare requirements. The analysis considers performance trends and supply chain considerations of Hydro One's various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spares requirement is intended to replenish inventory that is expected to be drawn down for future failures.

This program also covers the purchase of mobile transformers to facilitate planned outages, as well as spare breakers, and bushings that are required as operating spares in case of equipment failure.

Table 7 outlines the proposed funding for test years 2017 and 2018, along with the spending levels for the bridge and historic years.

Table 7: Transmission Station Demand and Spares ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Transmission Station Demand and Spares*	-	-	-	27.2	20.5	25.3	25.8

**Previously these amounts were recorded as Power Transformers and Circuit Breakers.*

Hydro One manages the Transmission Station and Demand Spares category by grouping investments for demand work execution and the purchase of spare power equipment. Details of specific programs are outlined in Table 8.

Table 8: Transmission Station Demand and Spares ($ Millions)

Ref #	Description	Test Years	
		2017	**2018**
S51	Demand Capital – Power Transformers	8.0	8.2
S52	Minor Component Demand Capital	4.7	4.7
S53	Operating Spare Transformer Purchases	8.2	8.3
	Other Demand and Spares Programs	4.5	4.7
	Total	**25.3**	**25.8**

Additional details for these investments are provided in the Investment Summary Documents S51 to S53 in Exhibit B1, Tab 3, Schedule 11.

4.2.4 Summary of Expenditures

The planned Transmission Station Demand and Spares expenditures for 2017 and 2018 are $25.3 million and $25.8 million respectively. The test year expenditures for the overall Transmission Station Demand and Spares program are based on historic spending required for emergency replacement of major power equipment and required equipment spare levels to effectively and prudently manage equipment failures. A reduction in this program will delay the replacement of failed equipment and will lead to maintaining a less than optimal spares inventory, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.

4.3 Protection and Automation (Control, Monitoring, Telecommunications and Cyber Security) Investments

4.3.1 Introduction

There are four key systems that protect, control and regulate the operation of the transmission system: protection systems, control systems, monitoring systems, and telecommunication systems.

Protection systems are devices connected throughout the transmission network for the purpose of sensing abnormal system conditions (e.g., as a result of natural events, physical accidents, and equipment failure). Upon sensing an abnormal condition, protection systems immediately operate the appropriate circuit breakers to isolate the affected equipment (e.g., transmission line, transformer, generator, and bus work) from sources of energy and the rest of the transmission system.

Control systems are used to facilitate the operating functions providing control and monitoring capability for each station to be operated remotely from the Ontario Grid Control Centre ("OGCC"), the back-up control centre, or locally at the station. Control systems also provide real time data to the IESO's energy management system in accordance with the Market Rules.

Disturbance Monitoring systems provide detailed, high speed records of normal and abnormal events that occur in stations or on transmission lines. These systems are required to meet NERC and IESO requirements, and are used to analyze the performance of protective relays and schemes and to ensure due diligence. The information obtained from monitoring systems is also used for maintenance scheduling, diagnostic analysis and post-mortem event analysis, consistent with good utility practice.

Power System Telecommunication systems provide high reliability and high-speed communication required for the protection, monitoring, and control of Hydro One's transmission system. These systems enable station-to-station communication, which helps minimize outage impact and equipment damage due to faults, and the remote monitoring and control of equipment throughout the system. Hydro One's telecommunication system consists of digital fiber-optic networks, Power Line Carrier ("PLC") systems, owned or leased metallic cables, digital microwave, and telecommunication equipment associated with the primary systems.

4.3.2 Investment Plan

The funding for Protection and Automation is summarized in Table 9 below and is significantly reduced for 2016, 2017 and 2018, as the majority of the capital spending will be provided as part of the integrated station projects. The integrated investment approach will help improve efficiency over individual protection and telecommunication upgrades. The funding shown below is required to support selective investments outside of integrated investments approach that are time sensitive, compliance, safety or customer-driven upgrades.

Hydro One is committed to maintaining top quartile reliability in comparison to its peers consistent with its business objectives. Based on Hydro One's risk assessment, work will be done to equip some stations for a higher level of performance or security.

Despite the inherent efficiency and benefits from integrated investment approach, there are exceptions that result in asset based investments.

Protection, Control, Monitoring and Telecommunications Investments are divided into the three categories described below. The third category, the cyber security program, entails the implementation of systems and facilities to protect the transmission grid from cyber-attacks and sustain those systems in compliance with the NERC Critical Infrastructure Protection ("CIP") standards. In addition, the program addresses cyber security vulnerabilities in the power system.

1. Protection Control and Monitoring Equipment: Capital investments to refurbish or replace protection, control and monitoring equipment required outside of integrated investments, including those driven by customer or broader system needs.

2. Power System Telecommunication Equipment: Replacement of telecommunication devices and systems that are approaching end of life. Examples of such devices and systems are: teleprotection facilities, digital/fiber (SONET), Power Line Carrier (PLC) facilities and Microwave System.

3. Cyber Security: Development and implementation of solutions to meet the NERC cyber security standard requirements and to optimally plan the further work required to achieve compliance with evolving NERC standards and Hydro One security policies.

Table 9: Protection, Control, Monitoring, Telecommunications and Cyber Security ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Protection, Control and Monitoring	72.3	65.4	70.5	34.4	24.0	12.6	11.2
Power System Telecommunication Equipment	16.7	14.1	16.8	11.0	4.2	8.6	14.9
Cyber Security	6.0	4.8	10.6	14.7	17.4	24.0	33.0
Total	**95.0**	**84.4**	**97.9**	**60.2**	**45.6**	**45.2**	**59.1**

4.3.2.1 Protection and Automation (Control, Monitoring, Telecommunications and Cyber Security Investments)

Protection, Control and Monitoring assets exist in Hydro One’s transmission system in very large numbers. This class of assets includes: protective relays and their auxiliaries, remote terminal units (“RTU”), sequence of event recorders (“SER”), digital fault recorders, special protection schemes, local control systems, and revenue metering systems. There are over 12,000 protection and control systems, each system consisting of up to 100 components. These systems cannot be out of service for longer than several days without disruption of planned outages and impacting reliability.

It is critical to ensure that end of life assets or deteriorating assets have well-defined replacement criteria and are replaced before the onset of failures or rapidly increasing maintenance. In order to avoid major disruption to the transmission system, it is essential to plan and execute the replacement programs for these assets before failure. Specific replacement programs are outlined in Table 10.

Table 10: Protection, Control and Monitoring ($ Millions)

Ref#	Description	Test Years		Total Project Cost
		2017	2018	
S54	Transformer Protection Replacement due to 2nd Harmonic Misoperations	4.6	4.6	16.5
	Other Minor Investments < $3M	7.9	6.6	
	Total	**12.6**	**11.2**	

The Investment Summary Document for the Transformer Protection Replacement due to 2nd Harmonic Misoperations is filed under Exhibit B1, Tab 3, Schedule 11.

Other Minor Investments include PN Upgrades, Protection Replacement Program, Disturbance Monitoring Equipment Compliance, CAPE Upgrade and Modelling and ITC Protection & Telecom Replacement.

4.3.2.2 Power System Telecommunication

The telecommunication replacement program is primarily focused on replacing end of life telecommunications equipment that supports protection and control equipment throughout the transmission system. Efficiencies in this program are realized through coordination with the replacement of protection and control equipment. Replacements are prioritized based on asset performance and the sustainment of protection and control system in compliance with NPCC and NERC reliability standards. Specific replacement programs are outlined in Table 11.

Table 11: Power System Telecommunication ($ Millions)

Ref#	Description	Test Years 2017	Test Years 2018	Total Project Cost
S55	Replace Legacy SONET Systems	2.1	5.3	112.0
	Other Minor Investments < $3M	6.5	9.6	
	Total	**8.6**	**14.9**	

The Investment Summary Document for the Legacy SONET Systems is filed under Exhibit B1, Tab 3, Schedule 11.

<u>Other Minor Investments</u> include Demand Capital, SONET and Microwave System Device Replacement, Replace Aviation Obstruction lights, Migration of Protections to Fiber Networks, 48VDC Equipment Replacement, PMR Infrastructure Refresh, PLC System Refresh, Telecom Performance Improvements, L3P/L4P Telecom Upgrade.

4.3.2.3 Cyber Security

On November 22, 2013, Version 5 of the NERC Critical Infrastructure Protection ("CIP") standards was approved by the Federal Energy Regulatory Commission ("FERC"), extending the applicability of cyber security requirements to additional assets within Hydro One's transmission system. With the adoption of Version 5, the number of sites for evaluation and inclusion in the NERC CIP cyber security compliance program has increased. The new revision of this standard is to come into effect on July 1, 2016. Furthermore, on January 21, 2016 a set of Version 6 revision of the NERC CIP standards was approved by FERC. This further expands the number of sites affected and the work required to ensure that these facilities are cyber security compliant. Hydro One's cyber security program set out in this application primarily focuses on the protection of assets from cyber-attacks in compliance with the requirements of these new standards.

The cyber security capital driver has been established to identify capital expenditures to develop and implement solutions to meet the NERC cyber security standard requirements and to optimally plan the further work required to achieve compliance with evolving NERC standards. Specific programs are outlined in Table 12.

Table 12: Cyber Security Capital Projects ($ Millions)

Ref#	Description	Test Years		Total Project Cost
		2017	2018	
S56	Physical Security for Critical Stations (non CIP-014)	5.0	5.0	18.0
S57	CIP V6 Transient Cyber Assets & Removable Media	2.0	10.0	12.0
S58	PSIT Cyber Equipment EOL	5.0	6.0	11.0
S59	CIP-014 Physical Security Implementation	6.0	6.0	24.0
S60	NERC CIP V6 CAPEX - Low Impact Facilities	5.0	5.0	10.0
	Other Minor Investments	1.0	1.0	
	Total	**24.0**	**33.0**	

The Investment Summary Document for the projects listed above are filed under Exhibit B1, Tab 3, Schedule 11.

4.3.3 Summary of Expenditures

The planned expenditures for 2017 and 2018 are $45.2 million and $59.1 million, respectively. The majority of the upgrades under Protection, Control and Monitoring and Power System Telecommunication equipment are bundled along with the station integrated capital investments. Telecommunication equipment investment is increasing due to the effort to maintain the telecom infrastructure that is in declining condition. Investments in cyber security are also increasing as Hydro One continues to comply with NERC CIP V5 and V6 standard with new security measures. It is expected that Cyber

Security spending will ramp down after 2018 when all mandated NERC compliance are fulfilled.

A reduction in this program will result in an increase in the risk to the operation of the power system. Reductions in planned capital expenditures will limit the rate at which end of life protection, control, monitoring and telecommunications assets can be replaced, increasing the risk and frequency of failure. Failure of protection systems to immediately detect and isolate abnormal system conditions can cause widespread outages in local supply and the interconnected grid, as well as equipment damage and injury to workers and the public. The failure of control and monitoring equipment can result in the complete loss of remote operating control of a station by system operators, requiring the dispatch of field personnel to locally control the station. Reductions will also jeopardize compliance with NERC cyber security requirements.

4.4 Transmission Site Facilities

4.4.1 Introduction

Hydro One's site facilities and infrastructure systems are comprised of yard drainage, fire protection and detection, structural footings, station buildings, cranes, elevators, heating, ventilating and air conditioning (HVAC) systems, access roads, water supplies, sewage management, and fences at transmission stations. These systems provide infrastructure and support services to all other station components, prevent unauthorized access, and make the station site functional for equipment and staff.

4.4.2 Investment Plan

This program targets the refurbishment or replacement of site and building components within transmission stations typically designed to house Hydro One staff, and in some cases electrical assets (i.e. protection, control, and telecom components).

Projects included within this group typically include replacement of building roofs, replacement of HVAC systems, upgrades to the water supply and septic systems, site paving, building demolition or other refurbishments or enhancements to the station buildings. The projects within this category are outside of work completed as part of Integrated Station Investment category.

Table 13 outlines the proposed funding for test years 2017 and 2018 for Transmission Site Facilities, along with the spending levels for the bridge and historic years.

Table 13: Transmission Site Facilities ($ Millions)

Description	Historic Years				Bridge	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Transmission Site Facilities	23.4	22.9	30.0	20.3	9.4	6.7	6.7

Additional details for this project are provided in the Investment Summary Document S61 in Exhibit B1, Tab 3, Schedule 11.

4.4.3 Summary of Expenditures

The planned expenditures for 2017 and 2018 are $6.7 million and $6.7 million respectively. The test year expenditures for the overall Transmission Site Facilities program represent a decrease from average historic spending due to the inclusion of required site facility work within the integrated capital investment planning investments captured in the station integrated capital investment category. These investments address the needs of the specific infrastructure assets to maintain system and customer reliability; and to combat instances of theft from Hydro One transmission stations that impact public and employee safety, and which are prudent to complete outside of integrated capital investments.

5. LINES

Transmission lines are used to transmit electric power, via the integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One's transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV. Hydro One's transmission system consists of approximately 30,000 circuit km of overhead transmission lines located on about 21,000 km of rights-of-way and 270 circuit km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shieldwire, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems and grounding systems. The underground transmission lines are generally located in large urban centres.

Lines Sustaining Capital funding covers expenditures required to replace or refurbish overhead and underground transmission lines or specific components that have reached the end of their service life or are in a deteriorated condition. Hydro One manages its Lines Sustaining Capital programs by dividing the program into three categories:

1. Overhead Lines Refurbishment and Component Replacement: Capital investments to refurbish or replace line components, as well as tower refurbishment and coating and capital corrective work associated with clearance corrections and rights-of-way facilities. In addition, this program funds the capital investments to refurbish complete line sections on a project basis;

2. Secondary Land Use Projects: Projects where Hydro One is required to relocate its facilities to accommodate new roads or other infrastructure changes; and

3. Underground Cables Refurbishment and Replacement: Capital investments required to refurbish or replace cable sections and components.

Required funding for the test years, along with the spending levels for the bridge and historic years are provided in Table 14 for each of these categories.

Table 14: Lines Sustaining Capital ($ Millions)

Description	**Historic Years**				**Bridge Year**	**Test Years**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	65.3	92.0	119.4	125.0	170.7	237.0	323.4
Underground Cables Refurbishment and Replacement	1.6	32.8	20.6	3.5	1.4	2.3	22.5
Total	**66.8**	**124.8**	**140.0**	**128.4**	**172.2**	**239.3**	**345.9**

The overall Lines Sustaining Capital spending requirement for the 2017 and 2018 test years are considerably higher than historic years. These spending increases are required to address the overhead lines refurbishment, tower coating needs and insulator replacement needs as described in the Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6.

5.1 Transmission Lines Refurbishment Projects

5.1.1 Introduction

Transmission line conductors are one of the most critical elements of a transmission line, from both operational and safety perspectives. When the conductor condition deteriorates to a critical level, failures are likely to occur in multiple locations anywhere on a line section.

5.1.2 Investment Plan

Specific transmission line sections are selected for replacement from the assessment of condition, based on the conductor testing results and the criticality of the line. Conductors are assessed by removing samples from a line section and laboratory testing, or via a new non-destructive assessment tool, called LineVue. Hydro One also considers asset demographics and performance as well as the ability to minimize safety and reliability risks.

In addition to deteriorated conductor condition, line refurbishment investment may be initiated by steel structures in poor condition. Once the galvanized coating on a steel structure has been depleted, the bare steel becomes exposed to the environment and corrodes at a quicker rate. If the tower is not re-coated and corrosion is allowed to continue, components of the steel structures will begin to lose strength and eventually require replacement. Once a structure is identified as being in poor condition through visual inspection and measurement of the remaining zinc coating, a detailed corrosion assessment is conducted to determine whether it is possible to replace a portion of the steel structure and coat the remaining structure to protect it from corrosion or whether it is more economic to replace the entire structure.

Once selected, the entire transmission line section is then refurbished to meet present and future system requirements. The transmission lines identified for replacement are outlined in Table 15.

Table 15: Transmission Lines Refurbishment Projects ($ Millions)

Ref #	Description	Test Years		Total Project Cost
		2017	2018	
S62	Line Refurbishment Project - C22J/C24Z/C21J/C23Z	18.5	2.5	47.3
S63	Line Refurbishment Project - D2L Dymond x Upper Notch	8.4	0.0	31.6
S64	Line Refurbishment Project - C1A/C2A/C3A	1.8	3.5	5.3
S65	Line Refurbishment Project - N21W/N22W	4.1	11.9	23.6
S66	Line Refurbishment Project - B5G/B6G	4.4	11.4	16.7
S67	Line Refurbishment Project - D2L Upper Notch x Martin River	18.3	21.1	43.2
S68	Line Refurbishment Project - B3/B4	0.9	6.4	7.2
S69	Line Refurbishment Project - A8K/A9K	0.4	6.6	17.0
S70	Line Refurbishment Project - A7L/R1LB and 57M1	0.9	20.5	69.1
S71	Line Refurbishment Project - K1/K2	0.9	7.4	15.7
S72	Line Refurbishment Project - E1C	0.9	12.8	39.2
S73	Line Refurbishment Project - D6V/D7V	2.6	5.7	8.3
S74	Line Refurbishment Project - D2H/D3H	0.9	12.5	25.9
	Other Line Refurbishment Projects < $3M	4.1	20.8	
	Total	**67.1**	**143.1**	

5.1.3 Summary of Expenditures

The planned expenditures for 2017 and 2018 are $67.1 million and $143.1 million, respectively. The average spending in the test years is higher than the bridge year 2016, and historic spending. This increase is required to address the increasing number of conductors that are being identified as reaching end of life and in a deteriorating state through the conductor assessment and testing program.

A reduction in this program will result in an increase in line failures, which could leave customers without power for lengthy periods of time until repairs are made, and/or create safety hazards for the public.

5.2 Overhead Lines Component Replacement Programs

5.2.1 Introduction

Hydro One's transmission system consists of approximately 30,000 circuit km of overhead transmission lines. In many cases, it is more cost-effective to replace one or more of the transmission line components that have reached their end of life rather than to rebuild the entire line. Transmission line components include: wood poles, insulators, shieldwire, switches, and steel structures. This program focuses on the replacement of individual overhead line components, as well as addressing electrical clearance corrections, right-of-way upgrades and emergency replacements.

It should be noted that in terms of component replacement, the focus of this program is on overhead line components other than conductors. When a conductor reaches the end of its life, the project takes on a much larger scope than individual component replacement with an emphasis to replace all components nearing end of life. Such conductor replacement projects are addressed under the Transmission Lines Refurbishment Program, which is discussed above.

5.2.2 Investment Plan

The overhead component replacement program is grouped into categories to effectively manage the needs of the overhead line assets. Hydro One considers asset condition and performance, along with safety and regulatory compliance requirements, when carrying out assessments on line components to determine which components require replacement. Full details of the assessment are available in the Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6.

Table 17 outlines the proposed funding for the test years 2017 and 2018, along with spending levels for the bridge and historic years for each category.

Table 16: Overhead Lines Component Replacement Programs ($ Millions)

Description	**Historic Years**				**Bridge Year**	**Test Years**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Wood Pole Replacements	26.9	32.7	43.6	38.5	38.3	35.3	35.3
Steel Structure Coating	1.6	5.7	5.1	4.6	8.8	42.5	54.4
Steel Structure Foundation Refurbishments	3.3	4.5	3.6	1.6	3.9	7.8	7.8
Shieldwire Replacements	4.4	2.9	8.2	4.3	5.2	7.0	7.1
Insulator Replacements	3.3	6.9	3.8	2.8	26.1	63.9	61.4
Transmission Lines Emergency Restoration	8.0	8.2	8.7	8.8	8.3	8.7	8.8
Other Line Component Replacements	3.4	5.6	5.7	6.0	3.2	5.0	5.2
Total	**50.9**	**66.5**	**78.7**	**66.6**	**93.8**	**170.2**	**180.0**

<u>Wood Pole Replacements</u>
Hydro One utilizes both wood poles and steel structures to support overhead transmission lines. Hydro One's transmission system contains approximately 42,000 wood pole

structures. The replacement program is focused primarily on replacing wood poles that are at end of life. Wood poles are determined to be at end of life based on the results of wood pole tests and inspections, at which point they are scheduled for replacement. In addition to end of life replacements, Hydro One continues to address the defective 230 kV Gulfport type structures which are exhibiting pole deterioration on the inside.

Additional details for this program are provided in the Investment Summary Document S75 found in Exhibit B1, Tab 3, Schedule 11.

Steel Structure Coating

Hydro One's transmission system includes about 52,000 steel structures. As described in the Asset Needs Overview (Exhibit B1, Tab 2, Schedule 6) Steel structures are manufactured with a zinc-based galvanized coating that protects the underlying steel against corrosion. Assessment of the condition of the steel structure is carried out on an annual basis as part of the maintenance program, with a focus on transmission line sections that are older than 35 years and are located in highly corrosive areas or in locations where known problems exist. The assessments determine the amount of galvanizing that remains on the structure, or in the case where the coating is depleted, the amount of metal loss that has occurred. This program focuses on coating steel tower structures that the assessment has deemed in need of corrosion protection due to loss of galvanized coating. By re-coating the structures in a timely manner the life of the asset can be extended indefinitely. Failing to re-coat prior to corrosion setting in will ultimately lead to the towers needing replacement.

This program addresses the replacement of steel structures where the corrosion assessment has deemed the structure to be at end of life. Additional details for this program are provided in the Investment Summary Documents S76 in Exhibit B1, Tab 3, Schedule 11.

Steel Structure Foundation Refurbishments

The foundations of the transmission structures are integral to the strength of the steel structure. One of the earlier vintages of steel structures is the lattice steel structures which are constructed with a grillage (buried steel) foundation. These particular structure foundations are prone to deterioration of the protective zinc coating and/or corrosion at or below the ground line depending on the ground conditions. About 60% of lattice type steel towers on the Hydro One transmission system have grillage footings. The transmission lines foundation refurbishment program is focused on assessing the condition of the foundations and anchors and repairing or replacing foundations and anchors that have been found not to satisfy the original installed design requirements. The assessment of foundation uses a pre-specified rating system and the decision to coat, repair or replace depends on the severity of corrosion or metal loss found.

Additional details for this program are provided in the Investment Summary Document S77 in Exhibit B1, Tab 3, Schedule 11.

Shieldwire Replacements

The shieldwire in Hydro One's transmission system is primarily made up of galvanized steel wire that is positioned above the conductors to protect a circuit against lightning related outages and to provide continuity of the grounding system. When the zinc galvanizing has depleted, the underlying steel begins to corrode, resulting in pitting and loss of metal and eventual failure if not replaced in time. Hydro One maintains an on-going shieldwire assessment program. This program focuses on the replacement of shieldwire that testing has deemed to not meet the required design requirement and is at risk of failing and dropping to the ground.

Additional details for this program are provided in the Investment Summary Document S78 in Exhibit B1, Tab 3, Schedule 11.

Insulator Replacements

Insulators are used in Hydro One's overhead lines to suspend energized conductor from supporting structures typically made of wood and steel. Insulator failures result in outages and at times allow energized conductors to fall to the ground, creating safety hazards. Transmission line insulators' expected service life varies, depending on the type, design, manufacturer and their installed environment. Due to this large variation in the life expectancy some insulators require replacement before the conductor.

There are defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) which require replacement. The assessment of these assets is available in Exhibit B1, Tab 2, Schedule 6. This program addresses the replacement of insulators with conditions have deteriorated to the point of creating safety and reliability concerns.

Additional details for this program are provided in the Investment Summary Document S79 in Exhibit B1, Tab 3, Schedule 11.

Transmission Lines Emergency Restoration

A number of transmission line components fail each year due to adverse weather, component deterioration, vandalism, or through accidents caused by public activity. This demand driven program is needed to restore power following transmission line failures and to replace or repair those line components where there is an imminent danger of failure as identified through line patrols or asset assessment. The types of emergency work covered under this program includes the replacement of failed or defective transmission line components such as wood structures, cross-arms, towers, insulators, conductor, shieldwire and hardware.

Additional details for this program are provided in the Investment Summary Document S80 in Exhibit B1, Tab 3, Schedule 11.

Other Component Replacements

Other component replacements include replacement of switches, rights-of-way access components and aviation lights that have reached end of life. Replacements of these components are essential to maintain system reliability and to address public and employee safety risks. Transmission line clearance corrections are also part of this program and are required to reinstate electrical ratings for the circuit. This may involve raising a structure or installing an intermediate structure to increase clearances.

5.2.3 Summary of Expenditures

The planned expenditures for 2017 and 2018 are $170.2 million and $180.0 million, respectively. The primary drivers for the increases are the needs to address tower coating and replacement of insulators in the system. These asset needs are described in the Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6. In addition, more steel structure coatings are required due to corrosion and a reduction of structural integrity.

A reduction in this program will lead to an increase of line component failures which can result in significant safety hazards to the public and could leave customers without power for lengthy periods of time, until repairs can be made. Furthermore, reductions to steel structure and foundation coating programs will result in increased costs in the future for costly steel structure replacements once structures exceed optimum time to coat and repair.

5.3 Secondary Land Use and Recoverable Projects

5.3.1 Introduction

This program funds the relocation, removal, or reinforcement of transmission assets in order to facilitate third-party projects such as roadwork, transit systems, and other major infrastructure or development work that may encroach upon or impact Hydro One assets and rights-of-ways. The projects planned for the test years are outlined in Table 17. The size and complexity of these projects vary from year to year, and are fully recoverable.

Table 17: Secondary Land Use and Recoverable Projects ($ Millions)

Ref #	Description	Test Years		Total Project Cost
		2017	2018	
S81	Gordie Howe International Bridge (Recoverable)	12.7	12.5	33.0
S82	Manvers – Lafarge Aggregate Pit (Recoverable)	1.0	3.8	13.8
	Other Recoverable Projects < $3M	4.9	9.4	
	Total Cost	18.6	25.7	
	Contribution	18.9	25.4	
	Net Capital Cost	(0.3)	0.3	

Additional details for these projects are provided in the Investment Summary Documents S81 and S82 in Exhibit B1, Tab 3, Schedule 11.

5.3.2 Summary of Expenditures

The planned net expenditures for 2017 and 2018 are $(0.3) million and $0.3 million respectively. The expenditures for secondary land use projects are generally recoverable and the net capital costs are minimal.

5.4 Underground Cables Refurbishment and Replacement

5.4.1 Introduction

Hydro One's transmission system consists of approximately 270 circuit km of underground 115 kV and 230 kV transmission cables. The high voltage underground ("HVUG") cable systems are comprised of a number of sub-systems and components that need to function properly in an integrated manner to be able to deliver a reliable supply of electricity. The primary components and sub systems are:

- Underground cable that is made up of an inner core conductor of either copper or aluminum, insulation that is made of liquid impregnated paper or cross-linked polyethylene, and a protective sheath or steel pipe with a protective cover or coating;
- Cathodic protection systems, that protect the steel pipe against corrosion;
- Liquid pressurization systems, that include pumping plants to ensure oil or gas pressure is maintained at acceptable levels;
- Bonding and grounding systems that address safety risks and control induction on the cable sheath; and
- Insulated cable terminations that connect a cable to an overhead line or connect a cable to a transformer station.

Hydro One's underground cable systems supply urban centres in Toronto, Ottawa and Hamilton, with short sections in London, Sarnia, Picton, Windsor and Thunder Bay. These underground cable systems are essential for electrical supply and as such require a very high degree of reliability. This program addresses the replacement or refurbishment of components and line sections of the HVUG cable system in order to maintain this reliability and mitigate safety concerns.

5.4.2 Investment Plan

Specific HVUG cable systems are selected for refurbishment or replacement once deemed at end of life due to their deteriorated condition. The decision to deem an underground cable and/or cable components at end of life is driven predominantly by cable performance, condition, and component obsolescence. Of particular importance is condition data that is gathered from cable diagnostics and maintenance activities such as condition patrols, cable pipe corrosion surveys, oil tests, jacket tests, infrared scans and intrusive examination of insulation systems when afforded the opportunity. Based on the asset assessment found in Exhibit B1, Tab 2, Schedule 6, entire cables or their subsystems are scheduled for replacement or refurbishment. Priority is given to assemblies and/or cables that are critical to the operation of the transmission system.

Planned capital investments in primary cable components and sub-systems vary from year to year depending on system needs. Table 20 outlines the planned projects for the test years. Additional details for these projects are provided in the Investment Summary Document S83 in Exhibit B1, Tab 3, Schedule 11.

Table 20: Underground Cable Projects ($ Millions)

Ref #	Description	Test Years		Total Cost
		2017	2018	
S83	H7L / H11L Cable Replacement	1.3	21.1	24.4
	Other Underground Cable Projects < $3M	1.0	1.3	
	Total	**2.3**	**22.5**	

Other underground cable projects include:

- Emergency repairs to the HVUG cable systems.
- Replacement of ring gaps associated with the cable bonding and grounding on the terminal ends of underground cables circuits. Studies have shown that due to rising

fault currents at some stations the current devices are no longer adequate during system fault situations and could fail explosively.

- Replacement of sump pumps that control water levels in cable tunnels that accommodate underground cable circuits.
- Upgrades to the cathodic protection isolation devices on the underground pipe type cables which are critical to mitigate the risk of corrosion to the steel carrier pipes that contain the insulated conductors.

5.4.3 Summary of Expenditures

The planned expenditures for 2017 and 2018 are $2.3 million and $22.5 million respectively. The cost in 2018 test year is significantly higher than the bridge year 2016. Since the initiation of H7L/H11L project, the targeted in-service date for this project has changed from December of 2016 to November of 2018 due to complexity of required environmental assessments and public consultations. As a result, the anticipated expenditures in the past few years have not been spent and have been shifted into the test years. This increase over historic years is required to replace a number of underground cable circuits that are in poor condition and are impacting the environment due to leakage of oil.

A reduction in this program will jeopardize the electrical supply reliability to the downtown areas of major centers in Ontario and increase environmental risks associated with an increase in oil leaks from these degrading cables.

DEVELOPMENT CAPITAL

1. INTRODUCTION

The Transmission Development Capital program is consistent with Hydro One's business objectives of providing exceptional customer service by building and maintaining a reliable and cost effective transmission system. The program covers funding for projects related to new or upgraded transmission facilities to:

- Provide inter-area network transfer capability to enable electricity to be delivered from areas with sources of supply to load centers;
- Provide adequate capacity to reliably deliver electricity to the local areas connected to Hydro One's transmission system;
- Connect load customers and generating stations to Hydro One's transmission system;
- Provide protection and control modifications to Hydro One's transmission stations to address the impacts of the distribution connected generation;
- Carry out necessary mitigation measures to minimize high impact risk and ensure safe, secure and reliable operation of Hydro One's transmission system in accordance with the Market Rules, Transmission System Code ("TSC") and other mandatory industry standards such as North American Electric Reliability Council ("NERC") and Northeast Power Coordinating Council ("NPCC"); and
- Expand the power quality data collection capabilities and pilot cost effective mitigation measures to address specific issues faced by Hydro One customers.

These Development projects take into consideration the need to plan and operate the interconnected bulk electric system in a safe, secure and reliable manner that meets Hydro One's transmission license requirements, responses to public policy, complies with criteria and standards, and is consistent with good utility practice.

Development projects to address specific customer needs are reviewed and coordinated with the customer to ensure investment plans reflect the customers desired outcomes. For projects that address regional needs, input, review and approval from the customers, such as distributors, occurs throughout the phases of the regional planning process as documented in Exhibit B1, Tab 2, Schedule 3.

Development projects are crucial to maintaining system reliability and ensuring the adequacy of electricity supply in the province. The importance of reliability is reinforced by the compliance obligations of various regulatory and reliability authorities to maintain acceptable voltages, keep equipment operating within established ratings, and maintain system stability during both normal operation and under recognized contingency conditions on the transmission system. These requirements include those of the NERC, the NPCC, the Ontario Energy Board ("OEB"), and the Independent Electricity System Operator ("IESO"), which utilizes its Ontario Resource and Transmission Assessment Criteria when conducting planning studies and System Impact Assessments for new transmission facilities. In particular, Hydro One is required to comply with the TSC and its Transmission License requirements.

2. DEVELOPMENT CAPITAL INVESTMENTS

Development Capital investments include work on both network and connection facilities. The investments are non-discretionary in nature as the need and timing is driven by requirements such as connecting new load and generation customers, upgrading existing delivery capability to meet customer demand, or increasing network transfer capability to enable electricity consumers to access supply. Investments to address these needs are planned and developed in conjunction with customers, the IESO and distributors under the regional planning process or the IESO as part of the planning for the bulk electric system. These investments are reviewed with all parties to ensure the preferred solution is feasible, prudent and cost-effective.

Since Development Capital investments are targeted to meet specific needs, the prioritization process for these investments is based on the development of an appropriate scope and schedule to meet the specific need and timing requirement. The goal is to ensure that these investments are implemented in a timely manner such that the transmission system is developed in a way that reflects and balances the needs of customers, regulators, asset owners, the IESO, and affected communities. Therefore the overall spending on Development Capital work varies year by year based on the type and the volume of investments being implemented. The proposed spending levels for each investment type are summarized in Table 1 below[1].

[1] Further details for some of the Investment Types listed in Table 1 have been excluded in this application as Hydro One is not proposing any capital spend in these areas over the test years. Specifically Station Equipment Upgrades & Additions to Facilitate Renewables and Smart Grid investments associated with Government Instructed initiatives that have been completed and no new initiatives are foreseen over the test years; as well as the Performance Enhancement work as it has been integrated into the other types of investments. These Investment Types are only included in Table 1 for continuity of historic spending.

Table 1: Development Capital
($Millions)

Investment Type	Historic				Bridge	Test	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Inter Area Network Transfer Capability	117.8	41.7	46.4	86.3	94.9	84.8	72.8
Local Area Supply Adequacy	95.7	61.9	61.2	95.8	58.5	50.5	54.3
Load Customer Connection	75.8	42.3	50.2	20.1	37.7	126.0	121.5
Generation Customer Connection	18.7	68.5	66.8	23.0	31.5	9.1	8.5
Protection and Control Modifications for Distributed Generation	25.0	23.8	13.7	9.6	4.4	6.0	5.5
Risk Mitigation	17.8	27.5	17.1	3.1	2.1	12.6	5.2
Customer Power Quality	0.0	0.0	0.0	0.0	2.1	2.1	2.1
Station Equipment Upgrades and Additions to Facilitate Renewables	32.7	15.7	0.3	0.2	0.0	0.0	0.0
Smart Grid	10.7	8.8	2.5	3.6	3.1	0.0	0.0
Performance Enhancement	0.7	0.1	0.5	1.3	0.3	0.0	0.0
Gross Capital Total	**394.9**	**290.3**	**258.7**	**243.0**	**234.6**	**291.0**	**269.9**
Capital Contributions	*(65.5)*	*(118.6)*	*(127.1)*	*(77.0)*	*(68.7)*	*(94.6)*	*(99.7)*
Net Capital Total	**329.4**	**171.7**	**131.6**	**166.0**	**166.0**	**196.4**	**170.2**

The overall gross expenditure planned for the test years, although higher than the bridge year spending, is comparable to the average level of spending over the historic years. One of the main contributors to planned expenditures in the test years is load customer connection, which accounts for nearly half of the total gross expenditure.

Further details for each investment type are provided in Sections 2.1 to 2.7 below, which include explanations of changes in spending patterns compared to historic levels, a brief summary of major projects and, where appropriate, identification of investments attributable to the regional planning process.

2.1 Inter-Area Network Transfer Capability

2.1.1 Description of Inter-Area Network Transfer Capability Investments

The integrated inter-area network, or bulk electric system, operates primarily at 500kV or 230kV (and 115kV in portions of northern Ontario) over relatively long distances incorporating major generation resources and delivering their output to major load centers in the Province through interconnection points to major transmission stations. The network is also interconnected with the transmission systems in Manitoba, Québec, Michigan, Minnesota, and New York enabling imports and exports of electricity.

The investments in the Inter-Area Network Transfer Capability category provide new or upgraded transmission facilities to increase the transfer capability between generation areas and load centers within Ontario and/or with neighbouring utilities, on the basis of planned changes in generation sources and load patterns.

The scope of solutions for improving transfer capability can range from minor upgrades at existing stations to major transmission reinforcement or interconnection projects. The major network upgrades involve long lead-times in the approval process (based on requirements under the *Environmental Assessment Act* and/or Section 92/95 of the *Ontario Energy Board Act* and construction of the project.

The consequences of not proceeding with these investments include increased risks to reliability and security of the interconnected system as a result of the lack of adequate transmission capacity to integrate supply sources and load demand. Constraints in the provincial transmission system can inhibit the use of Ontario's own generation resources, and imports and exports of power through interconnection facilities. These would result in negative economic or supply adequacy impacts, as well as potentially inhibiting the fulfillment of contractual provisions under agreements signed by the Ontario Government and the IESO (*the former OPA*[2]).

Funding levels for 2017 and 2018 for Inter-Area Network Transfer Capability projects, along with the spending levels for the bridge and historic years are provided in Table 2 below. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in the table.

The Inter-Area Network Transfer Capability category typically consists of a few projects with large multi-year spending; therefore the level of investment fluctuates based on timing of the project execution. The overall gross expenditure for the test years is comparable to the average spending level in 2015 and 2016. However, the comparison of the net expenditures over the same period is lower due to the capital contributions forecasted over the test years for the connection of the HVDC Lake Erie circuit at Nanticoke TS.

[2] As of January 1, 2015 the Ontario Power Authority ("OPA") merged with the IESO to create a new organization called the IESO that combines the OPA and IESO mandates.

Table 2: Inter-Area Network Transfer Capability:

Summary of Development Capital Projects in Excess of $3 Million

ISD #	**Investment Description**	**Capital Project Category[1]**	**Gross Capital Expenditures ($ Millions)**										**In-Service Years**
			Historic				**Bridge**	**Test**		**Gross Total Cost[2]**	**Capital Contribution[3]**	**Net Total Cost[4]**	
			2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**				
D01	Clarington TS: Build new 500/230kV Station	2	6.8	4.5	30.1	79.3	76.7	68.6	14.8	280.7	0.0	280.7	Q4 2018
D02	Nanticoke TS: Connect HVDC Lake Erie Circuit	3	0.0	0.0	0.0	0.0	1.0	5.0	13.0	36.0	36.0	0.0	Q4 2019
D03	Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade	4	0.0	0.0	0.0	0.0	0.3	2.5	8.0	20.0	0.0	20.0	Q1 2020
D04	East-West Tie Expansion: Station Work	3	0.0	0.0	1.0	0.1	0.0	3.0	30.0	166.1	0.0	166.1	Q4 2020
D05	Milton SS: Station Expansion and Connect 230kV Circuits	4	0.0	0.0	0.0	0.0	0.1	2.0	5.0	250.0	0.0	250.0	Q2 2022
	Other Projects <$3M (2017-18 Cash flows)[5]		0.0	0.1	0.1	6.9	16.9	3.7	2.0				
	Other Historical Projects (pre-2017)[6]		111.0	37.1	15.2	0.0	0.0	0.0	0.0				
		Total Gross	**117.8**	**41.7**	**46.4**	**86.3**	**94.9**	**84.8**	**72.8**				
		Capital Contribution	*0.0*	*0.0*	*(0.5)*	*0.0*	*(1.0)*	*(5.0)*	*(13.0)*				
		Total Net	**117.8**	**41.7**	**45.9**	**86.3**	**93.9**	**79.8**	**59.8**				

Notes:

1. **Capital Project Category** classifications provide an indication as to when specific projects would be considered approved for inclusion in rate base.

- ***Category 1*** - Development capital projects for which the OEB has already granted project-specific approval in another proceeding (for example, a proceeding for approval of the project under Section 92 of the OEB Act). For these projects, the actual in-service costs would be included in rate base when the project goes in-service.

- ***Category 2*** - Development capital projects that have an in-service date in one of the test years (2017 or 2018) and that do not require an approval under Section 92 of the OEB Act or any other such Board proceeding. Through the current proceeding, Hydro One is seeking approval for these projects to be included in the rate base when the projects are declared in-service.

- ***Category 3*** - Development capital projects that have significant spending within the test years (2017 or 2018), yet do not have an in-service date in any of the test years and do not require project-specific approvals from the OEB. For these projects, Hydro One is seeking guidance from the OEB on the appropriateness of the need, the proposed solution, and the recoverability of the project cost. The actual in-service costs would be included in rate base when the project goes in-service subject to Board approval at a future revenue requirement proceeding.

- ***Category 4*** - Development capital projects that have significant cash flows within the test years but they will require future project-specific approvals from the OEB in the form of Section 92 applications. Hydro One is not seeking approvals for these projects within this application since the prudency review for these projects will be tested during the Section 92 application process.

2. **Gross Total Cost**: The total plan costs, including the sum of the cash flows in the years before 2017 and after 2018 and the amount of customer contribution where applicable.

3. **Capital Contribution:** The sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary.

4. **Net Total Cost:** Gross Total Cost minus Capital Contribution.

5. **Other Projects < $3M:** The accumulated gross cash flows for projects that require non-expenditures of less than $3 million in either 2017 or 2018.

6. **Other Historical Projects:** The accumulated gross cash flows in historic and bridge years for projects that do not have any expenditure in either 2017 or 2018.

2.1.2 Summary of Inter-Area Network Transfer Capability Projects

The following summarizes the major inter-area network transfer capability projects identified in Table 2. All of the projects described below are non-discretionary, as defined in the OEB Filing Requirements for Electricity Transmission Applications. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit B1, Tab 3, Schedule 11.

Project D01: *Clarington TS: Build new 500/230kV Station*

This project is required to provide additional 500/230kV auto-transformation facilities, and reactive support following the retirement of the Pickering Nuclear Generating Station. This project also improves the 230kV supply security and restoration capabilities to the Pickering, Ajax, Oshawa and Clarington areas. The need for this project was provided by the former OPA and documented in evidence in proceeding EB-2012-0031 in a report entitled “OPA Information on the Description of Need and Rationale for “Oshawa Area” TS (i.e. Clarington TS)”.

The proposed transmission solution entails the construction of a new 500/230 kV station on Hydro One owned lands at the Clarington Junction Site. The new station will sectionalize and connect the five existing 230kV circuits that emanate from Cherrywood TS. Hydro One has obtained all necessary approvals for building the new station and the project is now under construction.

Project D02: ***Nanticoke TS: Connect HVDC Lake Erie Circuit***

This project is required to connect the 1000MW HVDC line between Ontario and Pennsylvania, proposed by the ITC Lake Erie Connector Company ("ITC"), to the Hydro One's transmission system.

This project entails the installation of necessary switching facilities at Hydro One's Nanticoke TS 500kV switchyard in order to connect the ITC line. The cost of this work will be recovered from ITC. ITC has applied to the National Energy Board in Canada and the US Department of Energy for necessary project approvals.

Project D03: ***Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade***

This project is required to increase the loading capability of the 230 kV circuits (M30A/M31A) in order to facilitate firm import capacity from Quebec as per the November 2014 Memorandum of Understanding between the Provinces of Ontario and Quebec.

The project entails upgrading the capability of the 230 kV circuits (M30A/M31A) between Hawthorne TS to Merivale TS by replacing the existing conductor with higher rated conductors. Hydro One will be seeking Board approval for this project under Section 92 of the *Ontario Energy Board Act*.

Project D04: ***East-West Tie Expansion: Station Work***

This project is required to connect the proposed 230kV double circuit East-West Tie between Wawa and Thunder Bay in order to maintain an acceptable standard of reliability in the region amidst load growth in the mining sector in the northwest coupled with the change in the regions supply mix (including the shutdown and conversion of coal-fueled power plants at Thunder Bay and Atikokan).

The Ministry of Energy, in a letter dated March 10, 2016, informed the OEB that under the authority of Section 96.1 (1) of the *Ontario Energy Board Act*, the Lieutenant Governor in Council made an order declaring that the construction of the East-West Tie transmission line is needed as a priority project.

This project entails the construction of necessary switching facilities to connect the new line at Wawa TS, Marathon TS and Lakehead TS; which includes switchgear, shunt reactors and capacitor banks. These facilities will provide for the connection of the new lines and permit an increased transfer level of 450MW. Hydro One will be seeking Board approval for the station facilities and associated line connections portion of the project under Section 92 of the *Ontario Energy Board Act*.

Project D05: Milton SS: Station Expansion and Connect 230 kV Circuits

This project is required to increase transfer capability and improve supply security as a result of continued load growth in the West GTA and increase inter-area flow due to major nuclear generation retirements and refurbishments. The need for this project was identified in the Northwest GTA Integrated Regional Resource plan.

The proposed transmission solution entails the construction of a new 500/230 kV transformer station at Milton SS and a new 230 kV double circuit transmission line from Milton SS to Hurontario SS. Hydro One will be seeking Board approval for this project under Section 92 of the *Ontario Energy Board Act*.

2.2 Local Area Supply Adequacy

2.2.1 Description of Local Area Supply Investments

The term 'local area', for the purpose of this exhibit, refers to a confined subsystem or radial portion of the system supplying multiple transmission delivery points serving one or more customers. The geographic and electrical size of a local area varies based on the area system characteristics and connectivity to the bulk electric system. The local area supply systems operate primarily at 230kV and 115kV, and they link the inter-area network to load centers, such as local distributing companies ("LDCs") and large industrial customers, and, in some cases, to local generators.

The investments in the Local Area Supply Adequacy category provide for new or upgraded facilities in order to: ensure area supply adequacy; maintain acceptable voltages; continue operation of equipment within the ratings; maintain system stability; and/or ensure operating flexibility; as well as to meet the load forecast requirements in an area where the loading on existing transmission facilities reach capacity. These investments typically affect many customers over a significant period of time and the benefits cannot be allocated in a practical and fair manner to specific customers.

The solutions for improving local area supply range from the utilization of special protection systems or installation of capacitor banks to maximize the use of existing facilities (in order to defer the need for a major investment) to major transmission expansion projects to meet long-term needs identified through the regional planning process. Major transmission expansion projects may include construction of new transmission lines into the area, and/or new or additional 230/115kV autotransformer capacity. These major projects typically require long lead-times, particularly if there are approval requirements under the *Environmental Assessment Act* or Section 92/95 of the *Ontario Energy Board Act*.

The consequences of not proceeding with these investments are dependent on the specific situation, and potentially include:

- Curtailment of load in order to ensure that the power system operates in a reliable mode and within the equipment rating;
- Insufficient reactive support causing system and voltage instability that would lead to widespread adverse impact in the local area; and
- System constraints that restrict the ability of new renewable or high efficiency generation to be connected.

Funding levels for 2017 and 2018 for Local Area Supply Adequacy projects, along with the spending levels for the bridge and historic years are provided in Table 3 below. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in the table. Customer capital contributions, where applicable, were determined in accordance with the TSC and Hydro One Transmission's Connection Procedures approved by the Board.

The overall gross expenditure for the test years is comparable to the bridge year spending; however it is lower than the average historic spending. Although there are several local area projects planned over the 2017 and 2018 period, these projects are not of the same magnitude as the major transmission reinforcement project identified in past rate applications, such as the Midtown Transmission Reinforcement Plan and the Guelph Area Transmission Reinforcement project.

1 **Table 3: Local Area Supply Adequacy: Summary of Development Capital Projects in Excess of $3 Million**

ISD #	Investment Description	Capital Project Category	Gross Capital Expenditures ($ Millions)										In-Service Years
			Historic				Bridge	Test		Gross Total Cost[1]	Capital Contri-bution[2]	Net Total Cost[3]	
			2012	2013	2014	2015	2016	2017	2018				
D06	Galt Junction: Install In-Line Switches on M20D/M21D Circuits	2	0.0	0.0	0.0	0.2	0.7	3.6	0.1	4.5	0.0	4.5	Q2 2017
D07	York Region: Increase Transmission Capability for B82V/B83V Circuits	2	0.0	0.0	0.2	1.2	7.5	22.6	0.2	31.8	0.0	31.8	Q4 2017
D08	Hawthorne TS: Autotransformer Upgrades	2	0.0	0.0	0.0	0.2	2.0	8.0	5.8	16.0	0.0	16.0	Q2 2018
D09	Brant TS: Install 115kV Switching Facilities	3	0.0	0.0	0.0	0.0	0.2	5.0	6.0	12.0	12.0	0.0	Q1 2019
D10	Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits	3	0.0	0.0	0.0	0.0	1.0	2.4	4.2	8.7	4.3	4.4	Q2 2019
D11	Southwest GTA Transmission Reinforcement	4	0.0	0.0	0.0	0.0	0.1	0.9	5.0	30.0	0.0	30.0	Q2 2020
D12	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits	4	0.0	0.0	0.0	0.0	1.0	4.0	20.0	80.0	0.0	80.0	Q4 2020
	Other Projects <$3M (2017-18 Cash flows)[4]		0.5	1.1	13.3	42.1	18.8	3.9	13.0				
	Other Historical Projects (pre-2017)[5]		95.2	60.8	47.7	52.1	27.3	0.0	0.0				
		Total Gross	**95.7**	**61.9**	**61.2**	**95.8**	**58.5**	**50.5**	**54.3**				
		Capital Contribution	*(9.2)*	*(7.9)*	*(12.1)*	*(30.9)*	*(10.3)*	*(6.7)*	*(8.6)*				
		Total Net	**86.4**	**54.0**	**49.1**	**64.9**	**48.2**	**43.8**	**45.7**				

Notes:

1. **Capital Project Category** classifications provide an indication as to when specific projects would be considered approved for inclusion in rate base.

- ***Category 1*** - Development capital projects for which the OEB has already granted project-specific approval in another proceeding (for example, a proceeding for approval of the project under Section 92 of the OEB Act). For these projects, the actual in-service costs would be included in rate base when the project goes in-service.

- ***Category 2*** - Development capital projects that have an in-service date in one of the test years (2017 or 2018) and that do not require an approval under Section 92 of the OEB Act or any other such Board proceeding. Through the current proceeding, Hydro One is seeking approval for these projects to be included in the rate base when the projects are declared in-service.

- ***Category 3*** - Development capital projects that have significant spending within the test years (2017 or 2018), yet do not have an in-service date in any of the test years and do not require project-specific approvals from the OEB. For these projects, Hydro One is seeking guidance from the OEB on the appropriateness of the need, the proposed solution, and the recoverability of the project cost. The actual in-service costs would be included in rate base when the project goes in-service subject to Board approval at a future revenue requirement proceeding.

- ***Category 4*** - Development capital projects that have significant cash flows within the test years but they will require future project-specific approvals from the OEB in the form of Section 92 applications. Hydro One is not seeking approvals for these projects within this application since the prudency review for these projects will be tested during the Section 92 application process.

2. **Gross Total Cost**: The total plan costs, including the sum of the cash flows in the years before 2017 and after 2018 and the amount of customer contribution where applicable.

3. **Capital Contribution:** The sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary.

4. **Net Total Cost:** Gross Total Cost minus Capital Contribution.

5. **Other Projects < $3M:** The accumulated gross cash flows for projects that require non-expenditures of less than $3 million in either 2017 or 2018.

6. **Other Historical Projects:** The accumulated gross cash flows in historic and bridge years for projects that do not have any expenditure in either 2017 or 2018.

2.2.2 Summary of Local Area Supply Projects

The following summarizes the major local area supply adequacy projects identified in Table 3. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit B1, Tab 3, Schedule 11.

Project D06: ***Galt Junction: Install In-Line Switches on M20D/M21D Circuits***

This project is required to improve the load restoration capability for the loads supplied from the 230 kV circuits (M20D/M21D) in the Cambridge and Kitchener area. The need for this project was identified in the Kitchener, Waterloo, Cambridge and Guelph ("KWCG") Regional Infrastructure Plan.

The project entails the installation of two 230kV in-line load interrupters switches at Galt Junction to enable the 230kV circuits (M20D/M21D) to be sectionalized in the event of a double circuit contingency; such that the supply to customers can be restored through connection to the unfaulted line sections.

Project D07: ***York Region: Increase Transmission Capability for B82V/B83V Circuits***

This project is required to increase the loading capability of the 230kV circuits (B82V/B83V) between Claireville TS to Brown Hill TS and to improve load restoration capability. This will address area supply reliability and provide adequate capacity to meet customer forecast load growth in northern Vaughan and York Region. The need for this project was identified in the GTA North Regional Infrastructure Plan.

This project entails the installation of new 230kV breakers and switches at Holland TS, and the implementation of a new load and generation rejection scheme at stations connected to the 230kV circuits (B82V/B83V).

Project D08: ***Hawthorne TS: Autotransformer Upgrades***

This project is required to provide additional transformation capacity to meet the forecasted load growth in the area and improve the area supply reliability. The need for this project was identified in the Greater Ottawa Area Regional Infrastructure Plan.

This project entails the replacement of two existing autotransformers at Hawthorne TS with new higher capacity transformers.

Project D09: ***Brant TS: Install 115kV Switching Facilities***

This project is required to increase the loading capability of the 115kV circuits (B12/B13) that supply Brant TS and Powerline MTS radially from Burlington TS in order to improve area supply reliability and provide adequate capacity to meet customer forecast load growth. The need for this project was identified in the Brant area Integrated Regional Resource Plan.

This project entails the installation of 115 kV switching facilities at Brant TS and the connection of the 115 kV circuit (B8W) to the 115 kV circuits (B12/B13).

Project D10: ***Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits***

This project is required to relieve overloading on the Hawthorne TS to Overbrook TS 115kV circuit (A4K). The need for this project was identified in the Greater Ottawa area Regional Infrastructure Plan.

This project entails rebuilding a short section of 115kV circuit (A5RK) from Riverside Junction to Overbrook TS as a double circuit line. The 115kV supply to Overbrook TS will then be moved from the existing A4K circuit to the new double circuit line.

Project D11: ***Southwest GTA Transmission Reinforcement***

This project is required to increase the 230kV transfer capability between Richview TS and Manby TS to meet forecast load growth in the Central Toronto and Southern Mississauga/Oakville areas. The need for this project was identified in the Metro Toronto area Regional Infrastructure Plan.

This project entails the replacement of an idle 115kV double circuit line between Richview TS and Manby TS with a new 230kV double circuit line. Hydro One will be seeking both Board approval under Section 92 of the *Ontario Energy Board Act*, as well as Class EA approval under the *Environmental Assessment Act*.

Project D12: ***Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits***

This project is required to provide additional supply capability in the Barrie area while addressing aging station facilities at Barrie TS and Essa TS. The need for this project was identified in the Need Assessment report conducted for the Southern Georgian Bay-Muskoka region. The IRRP for the region is still under progress; however, to meet the need date of 2020, the IRRP working group determined that transmission was the only feasible option. As a result, the IESO has issued a hand-off letter to Hydro One, dated December 7, 2015 to develop the preferred transmission plan consistent with the regional planning process.

The project entails the replacement of the existing 115 kV double circuit line (E3B/E4B) between Essa TS and Barrie TS with a new 230kV double circuit line; as well as the construction of a new 230/44 kV transformer station to replace the existing Barrie TS. Hydro One will be seeking both Board approval under Section 92 of the *Ontario Energy Board Act*, as well as Class EA approval under the *Environmental Assessment Act*.

2.3 Load Customer Connection

2.3.1 Description of Load Customer Connection Investments

Load customer connections can be addressed by new or modified transformation connection facilities including new feeder positions at existing transformer stations, or construction of new connection lines and stations. The projects are initiated based on the customers' requirements for capacity and reliability improvements. The projects may also be initiated by regional planning needs or the need to address end-of-life facilities.

In accordance with the TSC, new load connections driven by customer requests may be self-provided by the transmission customer or, at the discretion of the transmission customer, they may be provided by Hydro One. If requested, Hydro One is required by the TSC and its Transmission License to provide for new line connection and/or transformation connection facilities. The costs of these facilities are the responsibility of the benefiting customer(s) and the costs are fully recovered from these customers via incremental connection revenues and/or capital contribution as per a Connection Cost Recovery Agreement ("CCRA"), the calculation of which is based on Hydro One's Connection Procedures approved by the Board.

The consequences of not proceeding with these projects include: impairment of customers' ability to supply their current and expected loads, increased risk of rotating blackouts where existing facilities are overloaded, and/or violation of Hydro One's Transmission License, specifically, Section 8, "Obligation to Connect", and clause 5 which ensures that the company shall not refuse to make an offer to connect.

Funding levels for 2017 and 2018 for Load Customer Connection projects, along with the spending levels for the bridge and historic years are provided in Table 4 below. Projects with gross total funding requirements in excess of $3 million are separately identified in the table.

The Load Customer Connection category types of projects are primarily customer driven, and the magnitude and volume of work can vary significantly year over year based on customer requirements.

The overall gross expenditures for the test years have increased significantly compared to the average spending levels in the bridge and historic years. The primary reason for this increasing trend is customer need, driven by load increases and/or requirement for new connections.

1 **Table 4: Load Customer Connection: Summary of Development Capital Projects in Excess of $3 Million**

ISD #	Investment Description	Capital Project Category	Gross Capital Expenditures ($ Millions) Historic 2012	Historic 2013	Historic 2014	Historic 2015	Bridge 2016	Test 2017	Test 2018	Gross Total Cost[1]	Capital Contri-bution[2]	Net Total Cost[3]	In-Service Years
D13	Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D	2	0.0	0.0	0.1	1.1	0.4	10.0	5.9	17.5	14.0	3.5	Q1 2018
D14	Supply to Essex County Transmission Reinforcement	1	0.2	0.3	0.2	0.8	3.7	33.0	31.4	72.3	21.0	51.3	Q2 2018
D15	Horner TS: Build 230/27.6kV Transformer Station	2	0.0	0.0	0.0	0.0	3.0	16.0	13.0	32.0	26.9	5.1	Q2 2018
D16	Lisgar TS: Transformer Upgrades	2	0.0	0.0	0.0	0.1	1.0	10.3	2.5	13.9	3.9	10.0	Q2 2018
D17	Seaton MTS: Provide 230kV Line Connection	4	0.0	0.1	0.0	0.0	0.7	3.3	3.0	7.1	4.8	2.3	Q2 2018
D18	Hanmer TS: Build 230/44kV Transformer Station	3	0.0	0.0	0.0	0.0	0.2	9.5	18.5	30.0	5.6	24.4	Q1 2019
D19	Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits	4	0.0	0.0	0.0	0.0	5.0	23.0	17.0	47.0	21.8	25.2	Q1 2019
D20	Toyota Woodstock: Upgrade Station	4	0.0	0.0	0.0	0.0	0.5	3.0	2.5	6.0	6.0	0.0	Q1 2019
D21	Enfield TS: Build 230/44kV Transformer Station	3	0.0	0.0	0.0	0.0	0.5	10.0	15.0	33.1	22.4	10.7	Q2 2019
D22	TransCanada: Energy East Pipeline Conversion	3	0.0	0.0	0.8	0.6	1.0	1.9	10.2	175.6	175.6	0.0	Q4 2021
	Other Projects <$3M (2017-18 Cash flows)[4]		0.3	3.4	16.9	5.9	12.6	6.0	2.5				
	Other Historical Projects (pre-2017)[5]		75.3	38.5	32.2	11.6	9.1	0.0	0.0				
		Total Gross	**75.8**	**42.3**	**50.2**	**20.1**	**37.7**	**126.0**	**121.5**				
		Capital Contribution	*(15.2)*	*(17.6)*	*(35.6)*	*(12.4)*	*(21.6)*	*(67.9)*	*(64.1)*				
		Total Net	**60.6**	**24.7**	**14.6**	**7.7**	**16.0**	**58.1**	**57.4**				

<u>Notes:</u>

1. **Capital Project Category** classifications provide an indication as to when specific projects would be considered approved for inclusion in rate base.

- ***Category 1*** - Development capital projects for which the OEB has already granted project-specific approval in another proceeding (for example, a proceeding for approval of the project under Section 92 of the OEB Act). For these projects, the actual in-service costs would be included in rate base when the project goes in-service.

- ***Category 2*** - Development capital projects that have an in-service date in one of the test years (2017 or 2018) and that do not require an approval under Section 92 of the OEB Act or any other such Board proceeding. Through the current proceeding, Hydro One is seeking approval for these projects to be included in the rate base when the projects are declared in-service.

- ***Category 3*** - Development capital projects that have significant spending within the test years (2017 or 2018), yet do not have an in-service date in any of the test years and do not require project-specific approvals from the OEB. For these projects, Hydro One is seeking guidance from the OEB on the appropriateness of the need, the proposed solution, and the recoverability of the project cost. The actual in-service costs would be included in rate base when the project goes in-service subject to Board approval at a future revenue requirement proceeding.

- ***Category 4*** - Development capital projects that have significant cash flows within the test years but they will require future project-specific approvals from the OEB in the form of Section 92 applications. Hydro One is not seeking approvals for these projects within this application since the prudency review for these projects will be tested during the Section 92 application process.

2. **Gross Total Cost**: The total plan costs, including the sum of the cash flows in the years before 2017 and after 2018 and the amount of customer contribution where applicable.

3. **Capital Contribution:** The sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary.

4. **Net Total Cost:** Gross Total Cost minus Capital Contribution.

5. **Other Projects < $3M:** The accumulated gross cash flows for projects that require non-expenditures of less than $3 million in either 2017 or 2018.

6. **Other Historical Projects:** The accumulated gross cash flows in historic and bridge years for projects that do not have any expenditure in either 2017 or 2018.

2.3.2 Summary of Load Customer Connection Projects

The following summarizes the major load customer transformation connection projects identified in Table 4. All of these projects are non-discretionary and customer driven. Additional details about these projects are provided in the Investment Summary Documents in Exhibit B1, Tab 3, Schedule 11.

Project D13: ***Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D***

This project is required to increase the loading capability of the 115 kV circuit (E4D) to meet the load growth in the Red Lake area and to ensure adequate voltage for area customers. The need for this project was identified in the North of Dryden Integrated Regional Resource Plan.

The project entails improving the transmission line clearances in a number of locations along the 115 kV circuit between Dryden TS to Ears Falls TS; as well as the installation of capacitor banks at Red Lake TS and a special protection scheme at Dryden TS.

Project D14: ***Supply to Essex County Transmission Reinforcement ("SECTR")***

This project is required to meet future load growth in the Kingsville-Leamington area and to address the system restoration needs in the Windsor-Essex area. The need for this project was identified in the Windsor-Essex Regional Infrastructure Plan.

The project entails construction of a new 230/27.6 kV transformer station ("Leamington TS") and a 230 kV double circuit line between the new station and taps on the 230 kV circuits (C21J/C22J) between Chatham TS and Sandwich Junction.

The Board has granted approval to this project in proceeding EB-2013-0421 on July 16, 2015 under Section 92 of the *Ontario Energy Board Act*. An Environmental Study Report was filed with the Ministry of the Environment in July 2010.

Project D15: ***Horner TS: Build 230/27.6kV Transformer Station***

This project is required to provide additional transformation capacity in the southwest Toronto area to meet new load growth and to provide overloading relief at Manby TS. The need for this project was identified in the Metro Toronto Regional Infrastructure Plan.

The project entails construction of a second 230/27.6 kV transformer station on the existing Horner TS site.

Project D16: ***Lisgar TS: Transformer Upgrades***

This project is required to provide additional transformation capacity at Lisgar TS to meet area load growth and allow incorporation of embedded distributed generation in the area. The need for this project was identified in the Greater Ottawa Area Regional Infrastructure Plan.

This project entails the replacement of two existing transformers at Lisgar TS with new higher capacity transformers.

Project D17: ***Seaton MTS: Provide 230kV Line Connection***

This project is required to enable Veridian Connections Inc. (“Veridian”) to connect a new station in the North Pickering area to supply the new load growth anticipated for the

Seaton community. This project had been initiated by Veridian prior to the regional planning process. However, the need for this project was reaffirmed in the Need Assessment report and the IRRP (currently in progress) for the GTA East Region.

The project entails rebuilding a section of the 230kV single circuit line (C28C) from Cherrywood TS to Chats Fall TS as a 230kV double circuit line and provide a line connection to the new "Seaton" MTS. Depending on Veridian's site selection, Hydro One may be seeking Board approval under Section 92 of the *Ontario Energy Board Act*.

Project D18: ***Hanmer TS: Build 230/44kV Transformer Station***

This project is required to provide transformation capacity in the Greater Sudbury area to meet future load growth. This project also addresses end of life equipment and the standardization of sub-transmission to 44 kV in line with the other stations (Martindale TS and Clarabelle TS) that supply the area to improve load transfer capability between stations and improve supply reliability. The need for this project was identified in the Needs Assessment report for the Sudbury/Algoma region.

This project entails the construction of a new 230/44 kV transformer station at Hanmer TS to replace the existing 115/22kV Coniston TS. Hydro One Distribution will be building the 44kV distribution feeders from the new station.

Project D19: ***Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits***

This project is required to provide additional transformation capacity to meet new load growth in the West Toronto area served by Runnymede TS. The need for this project was identified in the Metro Toronto Regional Infrastructure Plan.

The project entails the construction of a second 115/27.6 kV transformer station at the existing Runnymede TS site. The 115kV circuits between Manby TS and Wiltshire TS will also be upgraded to provide the necessary transmission line capability. Hydro One will be seeking both Board approval under Section 92 of the *Ontario Energy Board Act*, as well as Class EA approval under the *Environmental Assessment Act*.

Project D20: ***Toyota Woodstock TS: Upgrade Station***

This project is required to provide a second 115kV supply connection to Toyota Woodstock TS. This work has been requested by the Toyota Motor Manufacturing Company to improve the station supply reliability.

This project entails extending the 115kV circuits K7/K8 to Toyota Woodstock TS and adding a second transformer at the station. Hydro One will be seeking Board approval under Section 92 of the *Ontario Energy Board Act*.

Project D21: ***Enfield TS: Build 230/44kV Transformer Station***

This project is required to provide additional transformation capacity to meet new load growth in the East Oshawa, Clarington Township and surrounding areas of the Eastern Durham region. The need for this project was identified in the GTA East local planning report.

The project entails construction of a 230/44 kV transformer station on the existing Clarington TS site. Hydro One Distribution and Oshawa PUC will be building distribution feeders from the new station.

Project D22: *TransCanada: Energy East Pipeline Conversion*

This project is required to provide electric supply to nineteen of TransCanada Energy's ("TCE") new pumping stations in order for TCE to convert one of its existing Canadian pipelines from natural gas to oil, allowing the transport of crude oil from Western Canada to Eastern Canadian refineries.

This project will require installation or reconfiguration of lines, stations and/or protection and control systems. Transmission work will also be required to facilitate the connection of two pumping stations at the distribution level. Hydro One is currently working with TCE to determine the specific connection scope required for each pumping station.

2.4 Generation Customer Connection

The investments in transmission connected generation are based solely on customer requests and are significantly impacted by external factors such as: the Ontario Government's initiatives, the IESO initiatives for new procurement of renewable, clean and high efficiency energy, and private sector investments.

In accordance with Hydro One's Transmission License, Hydro One is required to connect new generators that meet the requirements of the Market Rules and all other applicable codes, standards and rules while maintaining system security and reliability for existing connected customers. The costs of these investments are the responsibility of the benefiting customer(s) and the costs are fully recovered from these customers via capital contribution as per a CCRA. The customer capital contributions, as per a CCRA, are determined in accordance with the TSC, with clarification provided by the Compliance Bulletin #200606, dated September 11, 2006.

Generation customer connections are typically addressed by radial connection facilities; however, in some cases other modifications may be required to Hydro One's local area connection or network facilities in order to incorporate the generation into the system. Examples of modifications that may be required include enhancements to protection systems, voltage or reactive power support, and/or breaker and station upgrades due to increased short circuit levels contributed by the generator.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the Ontario Government or IESO or which have otherwise developed appropriately under the applicable codes and rules, many of which contribute to meeting the Ontario Government's targets for renewable electricity capacity; and
- Failure to meet Hydro One Transmission's obligation to connect new generators under its Transmission License and the TSC.

Funding levels for 2017 and 2018 for Generation Customer Connection projects, along with the spending levels for the bridge and historic years, are provided in Table 5 below.

The overall spending in the test years is significantly lower than historic spending. Generation connection activity has decreased in recent years as the major transmission connected generation procurement programs (i.e. Renewables Request for Proposals ("RFPs"), Clean Generation RFPs, Combined Heat and Power RFPs, Feed-In Tariff, and other project procurements) initiated by the Ontario Government and the IESO have been completed.

Table 5: Generation Customer Connection: Summary of Development Capital Programs

Investment Description	Gross Capital Expenditures ($ Millions)						
	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
Generation Customer Connections	18.7	68.5	66.8	23.0	31.5	9.1	8.5
Capital Contributions	*(18.9)*	*(68.8)*	*(65.0)*	*(24.6)*	*(32.7)*	*(9.1)*	*(8.5)*
Total Net Capital	**(0.2)**	**(0.3)**	**1.7**	**(1.7)**	**(1.2)**	**0.0**	**0.0**

2.5 Protection and Control Modifications for Distributed Generation

The connection of generation to the distribution systems supplied from the Hydro One transmission system requires a number of modifications and additions to the protection and control systems in the transmission stations. The need for these modifications is identified during the connection impact assessment process. These modifications are required to preserve the reliability and loading capability of the transmission feeders, to protect loads and generators from islanding, to preserve the proper function of station protections and to minimize disruption to the operation of the generators.

The consequences of not proceeding with these programs include:

- Severe restriction on the amount of generation that can be connected to distribution systems; and
- Lost production periods for station generator customers as a result of planned or forced transmission conditions for which transfer trip protections are not valid.

Funding levels for 2017 and 2018 for the Protection and Control Modifications program is provided in Table 6 along with the spending levels for the bridge and historic years. This work planned for the test years is non-discretionary and the costs are fully recovered through customer contribution, as these costs are directly associated with customers' connections.

The overall gross spending in the test years is significantly lower than historic spending. This is reflective of the slower pace of the generation customer connections as noted in Section 2.4. Additional details about the program are provided in the Investment Summary Document D23 in Exhibit B1, Tab 11, and Schedule 3.

Table 6: Protection and Control Modifications: Summary of Development Capital Programs

Investment Description	Gross Capital Expenditures ($ Millions)						
	Historic				Bridge	Test	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Protection and Control Modifications	25.0	23.8	13.7	9.6	4.4	6.0	5.5
Capital Contributions	*(22.5)*	*(22.6)*	*(12.5)*	*(7.5)*	*(3.0)*	*(6.0)*	*(5.5)*
Total Net Capital	**2.5**	**1.2**	**1.2**	**2.1**	**1.4**	**0.0**	**0.0**

2.6 Risk Mitigation

The risk mitigation investments cover work required to mitigate high risk situations and/or ensure compliance with mandatory standards (such as NERC, NPCC); as such this work is non-discretionary in nature.

With the exception of Force Majeure events such as the 1998 ice storm and the 2003 blackout, events presenting unacceptable risks to supply reliability are identified. Projects are identified to address needs on a priority basis considering legislative, regulatory, and environmental and safety requirements. Accordingly, the funding levels under this program can vary based on the issues to be addressed and the required remedial actions.

The consequences of not proceeding with these investments include: non-compliance with the applicable regulatory requirements, increased customer complaints, and inability to mitigate high-risk safety, security and reliability issues.

Funding levels for 2017 and 2018 for Risk Mitigation program, along with the spending levels for the bridge and historic years are provided in Table 7 below. The overall spending in 2017 test year is significantly higher than the forecast spending in the bridge year; however it is still below the historic spending over the 2012 to 2014 period where significant investments were made to address reliability and equipment risk at Allanburg TS, Hawthorne TS, Basin TS and Main TS as described in proceeding EB-2012-0031.

The higher 2017 expenditures reflect the requirement to provide a new station service supply at Nanticoke TS, as described in the Investment Summary Document D24 in Exhibit B1, Tab 3, Schedule 11. Once the Nanticoke TS project is completed, the overall spending in 2018 returns to a level of spending comparable to the expenditures in the historic years 2015 and 2016.

Table 7: Risk Mitigation: Summary of Development Capital Program

Investment Description	Gross Capital Expenditures ($ Millions)						
	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
Nanticoke TS: New Station Service Supply	0.0	0.0	0.0	0.0	1.0	10.0	0.0
Other Projects <$3M (2017/18 Cash flows)	3.1	3.0	1.7	1.1	0.9	2.6	5.2
Other Historical Projects (pre-2017)	14.7	24.5	15.4	2.0	0.2	0.0	0.0
Total Gross Capital	**17.8**	**27.5**	**17.1**	**3.1**	**2.1**	**12.6**	**5.2**
Capital Contributions	*(0.1)*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total Net Capital	**17.7**	**27.5**	**17.1**	**3.1**	**2.1**	**12.6**	**5.2**

2.7 Customer Power Quality

The Customer Power Quality Program is designed to address the quality of delivered power which can materially impact customers' operations and satisfaction, as reaffirmed in the Customer Engagement consultations. The *impacts* of power quality issues are particular to individual customers and are functions of:

1. The nature, severity and frequency of the power quality issue; and
2. Customer resilience or "ride-through" capability.

It is clearly in the best interests of both customers and the transmission system to improve and sustain adequate levels of power quality. However, there are several challenges that transmission utilities face in actually doing so. Many power quality issues are inherent in the physical nature of a transmission system such as routine switching operations that may cause voltage spikes and dips. As well, the leading causes of power quality issues in North America are naturally occurring, wide-ranging events such as lightning and other weather events. These types of power quality issues are difficult, cost prohibitive and/or simply impossible to address in any wholesale, network-wide manner. However, there are certain power quality issues faced by customers that can be mitigated on a case by case basis.

In an effort to better understand the impacts of power quality issues upon customers, and based on feedback from the Customer Engagement consultations, Hydro One has undertaken an outreach and stakeholder program called the Power Quality working group. Based on this initial outreach, Hydro One's new power quality program is focused on the following four initiative streams:

1. Power quality monitoring and data acquisition;
2. Event analysis, correlation and modeling;
3. Mitigation development; and
4. Customer support.

These initiative streams consist of both a proactive component of predicting and informing customers of potential system-specific power quality problems as well as a responsive component of addressing customer power quality issues on an ad hoc demand basis. These combine to address the impacts of power quality by improving system power quality performance or improving customer resilience or both. Both these initiative streams have Capital and OM&A components. The OM&A component is described further in Exhibit C1, Tab 2, Schedule 3.

The specific investments under Customer Power Quality capital program include:

1. Installation of power quality meters at transmission stations in cases where power quality issues are affecting a number of customers connected to a transmission facility. These meters will be located in a manner which maximizes the electrical coverage of power quality monitoring, and the correlation of power quality data with power system and customer events. Each meter will measure a range of power quality performance metrics including voltage sag, voltage dip, harmonics, voltage flicker, voltage and current imbalance. This performance data will be analyzed using such tools as PQWeb. Hydro One intends to install ten to fifteen power quality meters over each of the test years.

2. Installation of capacitor switchers with a specialized pre-insertion resistance feature to minimize switching transients, thereby reducing the risk of transient-induced tripping of sensitive customer equipment. These capacitor switchers are to be connected on either the low side of the transformers or the medium voltage buses. Hydro One intends to install two to three capacitor switchers over each of the test years. Locations are selected based on an analysis of system performance and a history of customers' issues related to capacitor bank switching.

Funding levels for 2017 and 2018 for the Customer Power Quality capital program, along with the spending levels for the bridge and historic years are provided in Table 8 below.

Table 8: Customer Power Quality: Summary of Development Capital Program

Investment Description	Gross Capital Expenditures ($ Millions)						
	Historic				Bridge	Test	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Customer Power Quality	0.0	0.0	0.0	0.0	2.1	2.1	2.1
Capital Contributions	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total Net Capital	**0.0**	**0.0**	**0.0**	**0.0**	**2.1**	**2.1**	**2.1**

3. LARGE CAPITAL PROJECTS WITH LIMITED SCOPE DEFINITION

The purpose of this section is to highlight certain large capital projects which have not been included in the investment plan or this rate application due to limited scope definition and project information.

There is currently only one large capital project which is this category. This project is expected to be in-service beyond the test years so it will not impact the rates being sought in this application. Unlike Category 3 projects, specific projection of yearly capital expenditures at a project level cannot be established at this time as this project is still in the study and scope definition phase.

While this project will not impact the rates in the test years, there may be significant capital expenditures in the test years for project development work, including approvals work, and early ordering of major materials that require long delivery times. Should this work materialize significant planning, engineering, approvals, stakeholder consultation and real estate resources will be required to carry out the work. Further description of this project is provided below.

<u>HV Reactors</u>

This project is to provide additional reactive power absorption capability to manage high voltages in the Greater Toronto Area ("GTA") and the Napanee area under light load conditions and/or equipment outage conditions involving generation or transmission facilities. The IESO has observed, in the last two years, a number of occasions of high voltages (i.e. voltages exceeding 550kV on the 500kV system and 250kV on the 230kV system) across the transmission system in the GTA and the Napanee area. The IESO system operators dealt with these incidences by opening lightly loaded transmission circuits between Bowmanville SS and Lennox TS. However, the IESO does not consider this action an appropriate long term remedy to this problem and a more permanent solution involving facilities to better regulate voltages and absorb reactive power is required.

To address high voltages in the GTA area, tap ratios on the 500/230kV autotransformers in the GTA have been adjusted. While this has mitigated the voltage issue in the GTA, Lennox TS 500kV bus still remains subject to over voltages under light load conditions. Preliminary studies conducted by the IESO have identified that the frequency and magnitude of the high voltage problem may worsen in future with the retirement of the Pickering Nuclear Generating Station and planned outages of units at Darlington GS due to refurbishment.

It is estimated that up to four HV reactors may be required at Lennox GS to address the Lennox overvoltage issue. More detailed studies are underway to further refine the scope of work, including the number, type, size and location of reactors needed. An in-service date of mid 2020 is being planned, in consideration of the lead time required for this project.

OPERATIONS CAPITAL

1. INTRODUCTION

Operations Capital investments fund enhancements and replacements of facilities required to operate Hydro One's Transmission System and to meet requirements established by operating agreements, market rules and regulatory authorities. These investments will provide monitoring and control functionality to maintain system reliability, accurate up to date information, improved customer satisfaction, reduced outage restoration time and ensure public and worker safety. The process to develop capital investments for Operations assets is discussed in Exhibit B1, Tab 2, Schedule 7.

Operations capital investments are required to:

- sustain facilities and technology due to technical obsolescence or end of life;
- perform major refurbishments to the OGCC and BUCC data centres to provide room for growth; and
- implement, enhance and modify the physical infrastructure, systems and tools necessary for transmission operations and to ensure regulatory compliance.

Failure to sustain the Network Operating systems and tools will lead to increased business and operational risk as deteriorating assets become less reliable, require more maintenance and lack vendor support. Network Operating system and/or tool failures negatively impact customer service, system reliability and regulatory compliance. It is important to our customers, the province of Ontario and our interconnected neighbours that Hydro One Transmission Operations prudently undertake investments necessary to operate the Transmission System to provide efficient, safe and reliable service.

The Operations Capital program for the test years is divided into two categories:

- **Grid Operations Control Facilities**: These investments fund enhancements and replacement of computer tools and systems, that support the transmission operating functions at the Ontario Grid Control Centre (OGCC) and the Back-Up Control Centre (BUCC), which will be replaced in 2020 by an Integrated Systems Operations Centre (ISOC) further discussed in section 3.3; and
- **Operating Infrastructure**: These investments fund enhancements and modifications to the physical infrastructure outside of the control centers, required for the effective operation of the Transmission System.

The required funding for the test years and the spending levels for the bridge and historic years is provided in Table 1.

Table 1: Operations Capital ($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**	
	2012	2013	2014	2015	2016	2017	2018
Grid Operations Control Facilities	3.4	11.3	23.3	14.2	18.7	11.4	19.3
Operating Infrastructure	11.9	6.4	5.0	1.4	11.4	14.0	11.5
Total	15.3	17.7	28.3	15.6	30.1	25.4	30.8

The expenditures in the test years are consistent with bridge year spending. Details are provided in the following sections.

2. DESCRIPTION OF THE SYSTEMS AND TOOLS

Hydro One operates and controls the Hydro One Transmission System from the OGCC. Back-Up facilities are provided at a separate location in the event that the OGCC or its computer systems are rendered unavailable. A suite of centralized systems and tools, supported by province wide telecommunication and station control infrastructure, is used to monitor and control transmission assets, plan and schedule outages and provide transmission system performance information. Hydro One continually assesses and implements new technologies to improve the performance and efficiency of its transmission operating function and the scheduling and real time management of equipment outages required to support the Sustainment and Development work programs. However, the operating function faces challenges associated with deteriorating assets that require closer monitoring and management of operating limits and equipment de-ratings resulting in increased workload.

2.1 Grid Operation Control Facilities

The primary systems used in the monitoring and control of the Transmission System include:

- **The Network Management System (NMS)** is the transmission network monitoring and control tool which performs the following functions: data acquisition, supervisory control, real-time and study mode network analysis, predictive assessments and training simulation. It provides the real time voltages, frequency, loading, equipment status and annunciates alarms for the change in status of equipment or if the equipment is in an abnormal condition on the Transmission System. The NMS also provides control of Hydro One Transmission assets in order to switch equipment in and out of service for outages, react to contingencies and change system configuration to provide reliable service to customers. The new NMS system, approved in EB-2014-0140 and EB-2012-0031, was commissioned in February of 2016.

- **Operations Support Tools** enable the integration of outage management, and Utility Work Protection Code and electronic logging functions:

  - **Network Outage Management System (NOMS)** is the transmission outage management tool used for planning, scheduling, assessing and executing transmission equipment outages and for transmitting outage approval requests, via a direct communication link, to the Independent Electricity System Operator (IESO). NOMS Version II was placed in production October 2010, and scheduled to be upgraded in 2017 and 2018.
  - The **Utility Work Protection** Code is used by Hydro One to establish conditions which, when combined with appropriate work practices, procedures and work methods, will provide employees with a guaranteed safe work area. This electronic work permit forms system contains the necessary information to support the development of required Work Protection documentation.
  - The **Electronic Log** is the records system for the daily control room activity. It has automated features to capture manual and automatic operations of transmission assets using the NMS. Other pertinent information including the Utility Work Protection Code, asset condition and status, and communications with customers and various entities are manually logged to create a chronological record of the daily activity. The electronic log provides system data for asset management and system planning.

- **Transmission and Station Operating Diagrams** provide detailed information on the normal operating configuration of the Transmission System and the electrical connection of the transmission system and station equipment. This information is essential for Work Protection applications and to ensure the safe and reliable operation of the Transmission System.

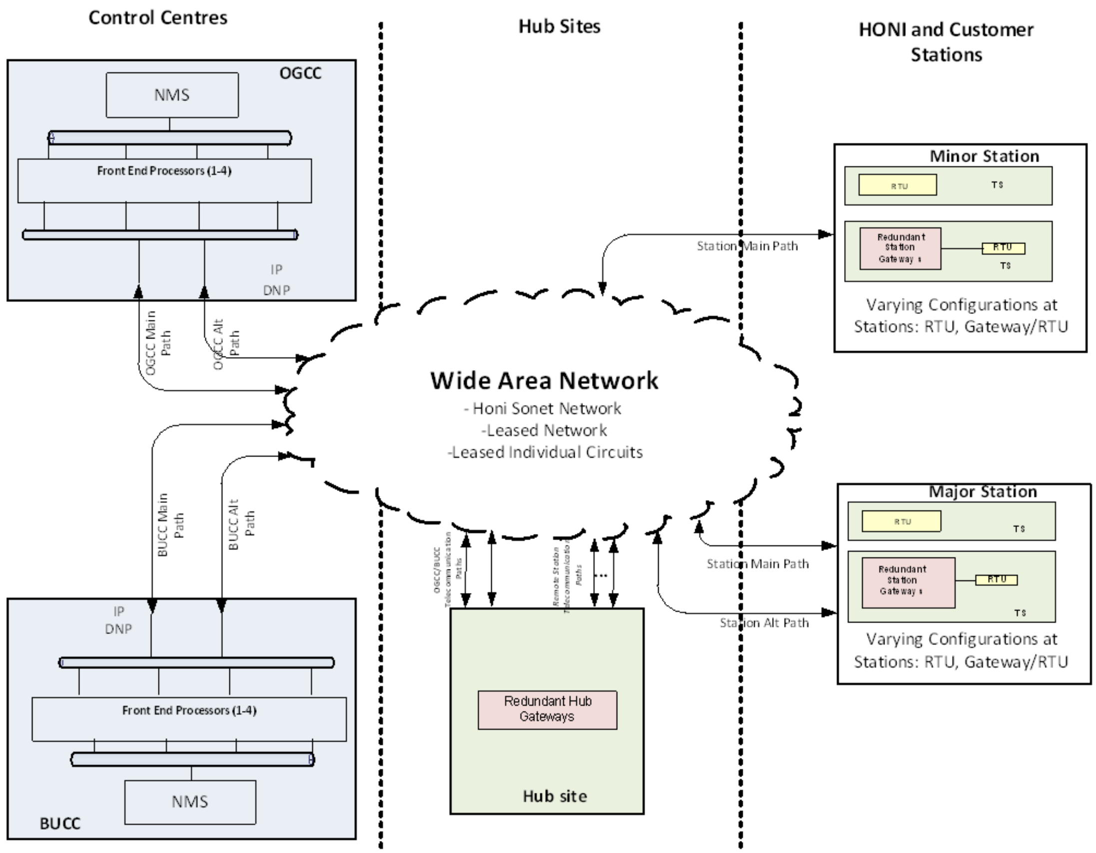
- The **Integrated Voice Communications & Telephony System (IVCT)** is designed to allow OGCC Operations to effectively manage voice communications between the OGCC and IESO, interconnected utilities, transmission connected customers, emergency services and field staff. Satellite phone systems and Hydro One's provincial mobile radio system are also available for emergency use. The new IVCT system approved in EB-2014-0140 was placed in service in December, 2015.

- The **Emergency Services Information System (ESIS)** provides verified up-to-date contact numbers for all emergency response services (e.g. police, fire, ambulance, ministry of environment, gas utilities, etc.) across the Province. This system is designed to enable Hydro One staff to quickly and effectively contact emergency personnel. The new ESIS was placed in service in October 2014.

2.2 Operating Infrastructure

Operating Infrastructure is comprised of the systems and telecommunications required to connect the OGCC and BUCC to transmission stations, to support real time field operations, and to fulfill Hydro One's obligations for real time telemetry under the Market Rules and Transmission System Code. Below is an overview of Hydro One's SCADA system.

Diagram 1: HONI SCADA System Overview



Specifically, Operating Infrastructure includes:

- **Hubsite Gateway Systems** that connect both legacy and integrated station control systems at approximately 300 transmission stations to computer tools and systems that support the transmission operating functions at the OGCC and Back-up Centres and to the systems at the IESO. There are hubsites located across the province collecting data from surrounding transmission facilities and sending them to the control center.

- **Station Gateway Systems** that connect both legacy and integrated station Protection and Control equipment via local network infrastructure to the associated hubsite.

- **Protection and Control Infrastructure** that includes station and hubsite routers and local control facilities. Station and hubsite routers provide access points to connect both legacy and integrated station P&C equipment to the Station Gateway Systems for the provision of real time monitoring and control information to the OGCC/BUCC. Local control facilities are used to provide local monitoring and control capability in the event of loss of telecom to the control center, allowing for continued monitoring and control of the facility.

- The **Wide Area Telecommunications Network** (WAN) provides independent paths on both Hydro One's Fibre Optic system and wireless media as well as on third party leased telecom, to all stations that are of critical importance to the operation of the grid and its restoration following any major disturbance event. This network also carries real time data to the IESO and real time data that Hydro One is obliged to provide to Transmission Connected Customers from the OGCC or Back-up Centre to local points of presence for these customers.

- The **Fault Locating Systems,** which are deployed at 14 stations monitoring 63 high voltage transmission lines, 43 of which are identified as high priority due to their remote location, promptly identify the location of failures on transmission circuits. These systems save on the cost and time associated with restoring circuits to service. Expansion to the existing system is planned.

- The **Provincial Mobile Radio System** is the means by which both the OGCC and the field operations centres maintain continuous high reliability contact with field crews. It is designed to be reliable in the event of localized or widespread blackouts and capable of accessing all remote, and electrically noisy, locations where Hydro One field crews would be dispatched. For health, safety and operational reasons, it is essential to provide crews with an assured means of communication in case of emergency.

- **Geomagnetically Induced Current Monitors** which detect currents flowing through the Transmission System induced by the earth's magnetic field during solar disturbances. These currents can disrupt protection systems and cause outages.

3. GRID OPERATIONS CONTROL FACILITIES

3.1 Overview

Grid Operations Control Facilities provide critical monitoring and operating technical capabilities and systems to support transmission operations at the OGCC and BUCC. The Grid Operations Control Facilities investments, discussed in sections 3.3 to 3.10, fund the enhancement and sustainment of computer tools and systems to maintain equipment performance, reliability and service quality, and to satisfy regulatory requirements.

Computer and network systems typically require renewal every five years due to technical obsolescence Grid Operations Control Facilities requiring upgrades are at end of life and are subject to increased reliability risk and maintenance costs as a result of lack of vendor support.

3.2 Investment Plan

The Capital projects for the Grid Operations Control Facilities are provided in Table 2.

Table 2: Grid Operations Control Facilities Capital Projects ($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Integrated System Operations Centre – New Facility	0.0	0.0	0.0	0.2	8.0	4.2	10.5
OGCC Data Centre Remediation – Interim Co-Location	0.0	0.0	0.0	0.0	1.2	0.6	0.6
OGCC *Data Centre Remediation*	0.0	0.0	0.0	0.0	3.5	1.5	1.7
OGCC Storage Area Network Upgrade	2.2	0.0	0.0	0.4	0.0	1.2	1.8
Operating Compute Refresh	0.0	0.0	0.0	0.0	0.6	2.0	1.0
NOMS Upgrade	0.0	0.0	0.0	0.0	0.4	0.9	1.1
NMS Enhancements	0.0	0.0	0.0	0.0	0.3	0.9	2.5
NMS Capital Sustainment	0.0	7.0	18.5	8.3	4.7	0.0	0.0
Other Historical Projects (pre-2017)	0.0	0.0	3.0	4.4	0.0	0.0	0.0
Miscellaneous	1.2	4.3	1.8	0.9	0.0	0.0	0.0
Total	**3.4**	**11.3**	**23.3**	**14.2**	**18.7**	**11.4**	**19.3**

3.3 Description of Investments

Table 3: Grid Operations Control Facilities

Capital Projects > $3 Million in Test Year 2017 or 2018 ($ Millions)

Ref #	Description	Cash Flow Test Years 2017	Cash Flow Test Years 2018	Total Cost	Removal Cost	Capital Cost
O01	Integrated System Operations Centre – New Facility	4.2	10.5	14.7	0.0	**14.7**
	Total Cost	4.2	10.5	14.7	0.0	**14.7**
	Removal Cost	0.0	0.0	0.0	0.0	**0.0**
	Capital Cost	4.2	10.5	14.7	0.0	**14.7**

3.4 Integrated System Operations Centre – New Facility Project (ISD-O01)

The Integrated System Operations Centre (ISOC) will house multiple lines of business through the provision of dedicated Control Rooms, an integrated shared Data Centre and shared back office support areas. This facility will be designed to withstand severe weather events (including tornadoes, earthquakes, etc.) to ensure continued operations, and will include strict adherence to NERC heightened physical and cyber security compliance standards. The ISOC is required as the Network Operating Division (NOD) BUCC is beyond designed capacity (e.g. no physical room for additional computers, inadequate heating, ventilation and air conditioning) and presents an increased risk of critical failures due to overheating and overloading of existing computers used to monitor and operate the growing number of assets. This has potential to render Hydro One non-compliant to NERC standard Emergency Operations Procedures (EOP-008-1) *Loss of Control Centre Functionality*” as Hydro One would not necessarily be able to gain control of the transmission system within the one hour time limit using the BUCC if the OGCC and/or its computer system were rendered unavailable.

The Back-Up Integrated Telecommunications Management Centre (BUITMC) can no longer meet planned business or operational requirements. The current centre cannot accommodate growth for the control room, back office support staff or critical computing equipment. Furthermore, the length of the time to activate the Back- Up centre is at risk of exceeding regulatory timelines that could result in a non-compliance with NERC. The BUITMC heating, ventilation and air conditioning (HVAC) is not adequate for occupancy nor for keeping the equipment cool. Lastly, the BUITMC lacks the necessary facilities should a prolonged activation be required. Security Operations (SOC) require primary centres for 24/7 operations and to mitigate reliance on third party services.

This investment was previously approved as the “Back-Up Control Centre (BUCC) – New Facility Development” in EB-2014-0140. However, Hydro One Network Operating has reviewed this investment in consideration of the requirements of other lines of business across Hydro One. The resultant expanded scope of work will maximize the capital investment through integration and shared utilization of the site, facility and critical infrastructure with all planned facility tenants. The current strategy maximizes synergistic operational security, restoration and response activities for Hydro One. The integrated site provides enhanced benefits and efficiencies due to economy of scale. Provisions for future growth as well as flexibility have been maximized to address the changing Operating environment. As a result of the expanded scope and the refinement of the investment, the planned in-service date has been shifted from 2018 to 2020.

It is essential to proceed with this investment to ensure compliance with regulatory requirements regarding having an operable Back-Up control facility with full functional monitoring and operation control of the Hydro One Transmission system.

The costs for the investments in the test years are $4.2 million in 2017 and $10.5 million in 2018.

The Investment Summary Document for the Integrated System Operations Centre – New Facility is filed at Exhibit B1, Tab 3, Schedule 11, Attachment 1.

3.5 OGCC Data Centre Remediation – Phase I - Interim Co-Location

The data centre at the OGCC has reached both physical and cooling capacity. To mitigate the capacity issue, Hydro One will lease an external facility in 2016 to allow for expansion of the existing data centre to maintain reliability and Hydro One's compliance with the relevant regulatory bodies (i.e. NERC, IESO). The long term approach is to split the capacity needs and address them in two stages; first stage is to expand capacity at the OGCC data centre via the "OGCC Data Centre Remediation" project. The second stage is to build additional capacity at the ISOC which will address both the medium and long term operating needs.

This investment will fund the lease of a co-locate facility to host critical computer equipment needed for operations during the transition phase to the ISOC facility, remediation of the OGCC data centre, facilitate the data centre expansion required to mitigate data centre capacity limitations and address issues such as but not limited to cooling, power supplies, and room availability. Not proceeding with the investment can result in decreased reliability of customer supply and the operation of the Bulk Electric System (BES).

The costs for the investments are $0.6 million in each of the test years.

3.6 OGCC Data Centre Remediation – Phase II

The OGCC data centre has reached capacity. This investment funds the required capacity expansion and improves reliability of the OGCC data centre. The project will redesign and restructure the OGCC data centre to optimize the space and cooling capacity, while making improvements to the supporting infrastructure to provision for future computing requirements.

Proceeding with this investment will minimize the risk of failure imposed by lack of cooling and power capacity, as well as mitigate the reliance on a third party. Phase I of the project will provide a temporary off site data centre. Not proceeding with this investment will pose a significant risk of data centre failure affecting the control and operation of the BES.

The costs for the investments in the test years are $1.5 million in 2017 and $1.7 million in 2018.

3.7 OGCC Storage Area Network Upgrade

The OGCC Storage Area Network (SAN) is the IT data storage at the OGCC and BUCC facilities. SAN infrastructure and archive provide a common data storage platform to Operating systems and applications including NOMS, NMS and other mission critical Operations systems and applications. This investment provides lifecycle management of SAN at the OGCC and BUCC to ensure continued operation. Not proceeding with this investment will result in Operating systems failures and loss of vendor support or at a minimum increases to support costs, negatively impacting the productivity of various lines of business that rely on such systems.

The costs for the investments in the test years are $1.2 million in 2017 and $1.8 million in 2018.

3.8 Operating Hardware Refresh

The Operating Compute refresh sustains common Operating IT hardware architecture and infrastructure including database servers and control room workstation console hardware and software. This infrastructure supports critical Network Operating Division power systems' applications such as NMS and NOMS. These systems will be at the risk of failure if the Operating IT hardware architecture is not maintained, which will lead to the inability to comply with the NERC specific requirement of possessing an operable outage planning system that exchanges information with the Reliability Coordinator (IESO). Also, replacing database servers and control room workstations when reaching vendor recommended end of life, will mitigate the risk of withdrawal of vendor support.

The cost for the investments in the test years are $2.0 million in 2017 and $1.0 in 2018.

3.9 Network Outage Management System (NOMS) Upgrade

NOMS is an essential tool for planning, scheduling, assessing and executing transmission and distribution equipment outages. This investment was formerly approved and named NOMS Sustainment in EB-2014-0140. The current version of NOMS was placed in production in October 2010 and a system refresh is required in 2016 (bridge year), and test years (2017 & 2018) in order to ensure continued vendor support and enhancements to the tool for greater operating efficiencies and safety.

This investment provides for the capital sustainment of the NOMS system. Planned investments include hardware refresh, operating system upgrade and the most affective option of either a refresh or a replacement of the application, including: software, system components, interfaces with corporate systems and other hardware as required. Not proceeding with this investment will result in the risk of withdrawal of vendor support, resulting in the increasing probability of system failure, which would seriously compromise business operations and violates IESO market rules.

The cost for this investment in the test years are $0.9 million in 2017 and $1.1 million in 2018.

3.10 Network Management System (NMS) Enhancements

Investment for NMS enhancements provides funding for changes to and capital sustainment of the NMS to meet NERC regulatory requirements. Enhancements will enable product and custom functionality with the integration of other applications. Continued sustainment of the mission critical NMS will ensure system adequacy for optimal operation of the Transmission System and focus on remaining top quartile for customer service, reliability, safety and system situational awareness for better decision making. This investment will allow Network Operating to provide continuous improvement to NMS to meet changes to regulatory and business requirements.

The costs for the investments in the test years are $0.9 million in 2017 and $2.5 in 2018.

3.11 Grid Operations Control Facilities Summary of Expenditure

Investments under this category mainly fund information technology (IT) assets, to allow Hydro One Networks to adequately manage IT lifecycles. This ensures vendor support for these critical assets is maintained in accordance with the mandated reliability and availability requirements as prescribed by the North American Electric Reliability Corporation (NERC). The pacing in spending levels noted in Table 2 is designed to match the various IT asset lifecycle requirements.

Additionally, the scope change and the investment required for the "Back-Up Control Centre (BUCC) – New Facility Development", also accounted for the noted variations in Table 2. The BUCC investment is further discussed in detail in section 3.4.

The sum of the planned expenditure for the test years is $30.7 million ($11.4 million in 2017 and $19.3 million in 2018).

4. OPERATING INFRASTRUCTURE

4.1 Overview

Operating Infrastructure provides support for transmission operations at the OGCC and BUCC. These investments fund enhancements, expansion and end of life replacement of the physical infrastructure, beyond the walls of the OGCC and BUCC. This is required for the operation of the Transmission System, to maintain equipment performance, reliability, maintain service quality of all critical systems and to comply with regulatory requirements.

Computer and Network systems typically require upgrades every five to ten years. The upgrade requirements are dependent on technology advancements, necessary software patches, loss of manufacturers' support and increased demands on functionality. As these systems reach end of life, they are replaced and sometimes expanded to manage increased reliability risks and to provide improved functionality.

4.2 Investment Plan

The capital projects/programs for Operating Infrastructure are provided in Table 4.

Table 4: Operating Infrastructure Capital Projects ($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**	
	2012	2013	2014	2015	2016	2017	2018
Grid Control Network Sustainment	0.0	0.0	0.0	0.0	4.2	5.8	3.0
Station Local Control Equipment Sustainment	0.0	0.0	0.0	0.0	2.5	3.6	3.7
Hub Site Management Program	0.0	0.0	0.0	0.0	2.5	2.6	2.6
Station Battery Monitoring Systems	0.0	0.0	0.0	0.0	0.8	0.8	1.4
Station LAN Infrastructure Program	1.6	0.7	1.0	1.0	0.0	1.0	0.5
Telemetry Expansion Program (Demand)	0.0	0.0	0.0	0.0	0.0	0.3	0.3
Other Historical Projects (pre-2017)	10.3	5.7	4.0	0.4	1.4	0.0	0.0
Total	**11.9**	**6.4**	**5.0**	**1.4**	**11.4**	**14.1**	**11.5**

4.3 Description of Investments

Table 5: Operating Infrastructure

Capital Projects > $3 Million in Test Year 2017 or 2018 ($ Millions)

Ref #	Description	Cash Flow Test Years		Total Cost	Removal Cost	Capital Cost
		2017	2018			
O02	Grid Control Network Sustainment	5.8	3.0	8.8	0.0	8.8
O03	Station Local Control Equipment Sustainment	3.6	3.7	7.3	0.0	7.3
	Other Projects/ Programs < $3M	4.7	4.8	9.5	0.0	9.5
	Total Cost	14.1	11.5	25.5	0.0	25.5
	Removal Cost	0.0	0.0	0.0	0.0	0.0
	Capital Cost	14.1	11.5	25.5	0.0	25.5

4.4 Grid Control Network Sustainment Program (ISD O02)

This is a continuation of a program to manage the end-of-life replacement of Grid Control Network elements. The program ensures the ongoing reliability and performance of control of the Grid by containing the rate of loss-of-control events to acceptable rates by replacement of network equipment just before end-of-life failure rates begin increasing. Additionally, the program avoids cost increases associated with maintenance of aging and obsolete equipment.

The cost for this investment in the test years is $5.8 million in 2017 and $3.0 million in 2018.

Additional detail for this program is provided in the Investment Summary Document in Exhibit B1, Tab 3, Schedule 11, Attachment 1.

4.5 Station Local Control Equipment Sustainment (ISD O03)

Local control equipment is critical to the operation of Ontario Grid as it provides local Power System Monitoring and Control (PSMC) of the entire station. Hydro One installs local control equipment at each remote station as a standard practice to operate the station; these stations are normally unmanned. In the event that Ontario Grid Control Centre (OGCC) or Backup Control Centre (BUCC) loses monitoring or control capabilities of the remote transformer stations, controllers dispatch field staff to monitor and operate the remote stations locally. This ensures immediate reaction to any contingencies that may affect reliability or safety.

This investment is to develop new solution for the Local Control Equipment and to fund end-of-life Local control equipment upgrades not covered under the station centric projects.

The cost for this investment in the test years is $3.6 million in 2017 and $3.7 million in 2018.

Additional detail for this program is provided in the Investment Summary Document in Exhibit B1, Tab 3, Schedule 11, Attachment 1.

4.6 Hubsite Management Program

Hubsites consist of gateways used to aggregate real-time monitoring and control data from multiple stations to the Ontario Grid Control Centre (OGCC) and the Backup Control Centre (BUCC) routers which provide the communication interface between the remote station legacy and integrated control systems as well as provide the communication interface to the OGCC and BUCC, including the new ISOC. The data collected at these sites is provided via redundant and diverse telecom paths directly to the OGCC and to the BUCC via disaster recovery sites which will facilitate restoration following loss of one of the control centres. Hubsites provide a cost effective means to reduce telecom utilization costs while providing increased reliability for monitoring and control capability by consolidating local telecom circuits within a geographic area and providing a fewer number of redundant and diverse paths back to the OGCC and BUCC. They also facilitate change control and provision of High Performance Data to the IESO in support of Market Rules requirements.

This program is required to expand the current thirty-six hubsites across the province to provide for capacity expansion for the monitoring and control of new assets, stations and generators that are connecting to the transmission system as well as addressing reliability requirements to support the safe, effective and efficient control of the grid. As new assets are built, the additional telemetry required increases the utilization of the gateways and increases the risk associated with the loss of a gateway resulting in a loss of monitoring and control capability for a larger number of stations. When a gateway approaches capacity and additional stations are added, more gateways and hub sites are required to maintain reliability and to minimize impact to the operation of the gird due to a loss. The hubsite management program continually manages these factors to ensure the capacity and reliability of the grid control infrastructure is in place to meet the needs of the development, load connection and transmission generation connection programs.

The plan to begin addressing the need for hub site infrastructure improvements has been delayed due to an extensive review of the power system monitoring and control reliability requirements, the need to align with NERC Critical Infrastructure Protection (CIP) requirements, and a review of the overall protection and control architecture strategy and reliability requirements necessary to support the new Distribution Automation Strategy.

In 2016, new hubsites are planned to provide capacity relief for the heavily loaded hubsites and to address reliability concerns associated with adjacent stations connected to the same hubsite which can have an impact on the operation of the network modelling system due to the loss of real-time data from adjacent stations. This work is planned to be implemented over the next five years and will be coordinated with end of life replacement for the original hubsite gateway hardware.

The cost for this investment in the test years is $2.6 million in 2017 and $2.6 million in 2018.

4.7 Station Battery Monitoring Systems

Station batteries are critical to maintaining reliable operation of the Power System. Power Equipment (breakers/switches), protection systems, control systems and telecom systems are all powered by the station battery. Improved station battery monitoring allows for improved reliability of the transmission grid particularly during power system events and blackouts. The DC system controls the operation of the transmission assets such as but not limited to breakers, switches and transformer tap changers. It also supplies the protective relaying schemes that will remove a defective asset from the system to avoid a cascading effect that could cause a wide spread interruption. NERC standards state that transmission elements that are not protected by instantaneous protection and can affect the security of the bulk electric system must be removed from service.

NERC PRC-005 defines the minimum maintenance activities and maximum maintenance intervals for station batteries for non-monitored battery systems as well as exclusions where monitoring attributes is available. The main intent of this program is to evaluate and install battery monitoring systems to reduce OM&A cost on station battery testing as well as improving efficiency of our battery maintenance program.

This program will install battery monitoring systems at identified bulk power system stations in order to provide operations with a better insight of station battery capacity and health and to reduce the need for ongoing testing.

The cost for this investment in the test years is $0.8 million in 2017 and $1.4 million in 2018.

4.8 Station Local Area Network (LAN) Infrastructure Project

Modern digital protection, control and monitoring devices located in a transmission station have the ability to be networked together. The networking of these devices provides many benefits in the form of reduced cabling costs, reduced cost for primary measuring devices or transducers, reduced design costs, and the ability to achieve business efficiencies by remote interrogation of the devices for fault locating, event analysis and asset utilization information.

This program installs a standardized LAN infrastructure, appropriate to the class of station, which incorporates cyber security, remote monitoring and has the capacity, or expandability, to meet all forecast needs.

The cost for this investment in the test years is $1.0 million in 2017 and $0.5 million in 2018. The budget is significantly lower compared to the previous rate filing as station LAN infrastructure is deployed as part of station centric projects.

4.9 Telemetry Expansion Program

The funding for this program is considerably lower than in previous years as this work is included in station centric project releases. For issues identified following post event analysis where it is identified that bundled alarms have delayed restoration or caused unnecessary equipment outages, this program will continue to fund the splitting of critical bundled alarms and the addition of more detailed monitoring of transmission equipment. This will enable OGCC to make an immediate determination of the cause of an alarm and the appropriate response. This will eliminate the need for unnecessarily removing equipment from service and urgent costly field staff dispatches to investigate the cause of the alarms. This program is required to eliminate unnecessary equipment outages, make more efficient use of field staff, better management of aging assets and improve grid reliability. The removal of any piece of equipment from service can place load supply at risk and may result in the delay of other outages required to complete sustainment or development work. Delay or cancellation of outages can be very disruptive to the execution of work affecting both schedules and costs.

The cost for this investment in the test years is $0.3 million in 2017 and $0.3 million in 2018.

4.10 Operating Infrastructure

The decreased spending in Operating Infrastructure from $11.9 million in 2012 to $6.4 million in 2013 can be mainly attributed to deferred implementation and eventual cancellation of the Wide Area Network (WAN) Project following re-assessment of the project scope in the context of other infrastructure and system needs. The planned spending in the bridge and test years, of $11.4 million in 2016, $14.0 million in 2017 and $11.5 million in 2018, is higher than the historic years due to the on-going funding for

Grid Control Network Sustainment for equipment end of life and release of hubsite expansion work. Implementation of hubsite realignment was delayed in the historic years to allow for a detailed review of requirements to address adjacency and reliability concerns. Program spending continues for specific telecommunication network improvements and additional work related to the mitigation of Local Control Equipment failures.

5. SUMMARY

Operations Capital investment requirements are necessary to ensure the reliable, safe and efficient supply of electricity to Hydro One’s transmission customers. These investments have been reviewed to ensure the most effective spend of funding that will allow Hydro One to meet its required regulatory obligations as a transmission owner and operator and to accommodate the growth and flexibility of the changing interconnected transmission system. Hydro One was very conscious of customers’ needs the development of the operations investment portfolio and believes these investments will set Hydro One up for future success in meeting their needs.

COMMON CORPORATE COSTS CAPITAL

1. OVERVIEW

Common Corporate capital expenditures support the Sustainment, Development, and Operations work programs of Hydro One. As such, they consist of assets that are largely shared by both the transmission and distribution businesses. Common Corporate capital includes information technology ("IT") installations, buildings, office equipment, transportation and work equipment, tools, and service equipment.

Table 1 provides a summary of the transmission portion of the Common Corporate capital costs over the historic, bridge and test years.

Table 1: Common Corporate and Other Capital Allocated to Transmission 2012-2018 ($ Millions)

	Historic				Bridge	Test	Test
Description	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Information Technology	30.5	22.9	26.8	21.6	33.6	31.4	28.1
Facilities & Real Estate	11.6	7.4	13.7	22.7	22.6	18.4	20.9
Transport, Work, and Service Equipment	14.6	18.8	22.0	22.1	26.1	24.1	25.0
Other (including Distribution Line Loss and CDM)	-14.7	0.0	0.9	0.7	1.2	3.7	5.1
Total	**42.1**	**49.1**	**63.4**	**67.1**	**83.5**	**77.6**	**79.1**

Exhibit B1, Tab 3, Schedule 9 outlines the appropriate cost drivers that have been utilized to derive the transmission allocation of this capital.

The level of spending in IT capital for the test years declines as compared to the bridge year, primarily due to a reduction in IT hardware and software costs. Exhibit B1, Tab 3, Schedule 6 details the capital requirements for IT.

The primary driver for facilities and real estate spending is the need to provide suitable space to accommodate the staff and equipment required by the Sustainment, Development and Operations work programs. Capital spending over the test years is relatively flat as compared to 2015 and the bridge year. Exhibit B1, Tab 3, Schedule 7 details the capital requirements for facilities and real estate.

The level of spending in transport, work and service equipment capital for the test and bridge years has increased slightly from historical levels due to progress payments for a helicopter. More details on these capital requirements are set out in Exhibit B1, Tab 3, Schedule 8.

In the test years, "Other" costs reflect the capitalized component of the Employee Share Ownership Program, the Long Term Incentive Program and the union share grants described in Exhibit C1, Tab 4, Schedule 1.

INFORMATION TECHNOLOGY

1. OVERVIEW

This section details the information technology ("IT") capital costs required for the test years to support business processes used by Hydro One's employees. IT capital expenditures include hardware and software for projects and programs that individually meets Hydro One's capitalization policy.

Table 1: Total IT Capital Expenditures ($Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2017**	**2018**
Hardware / Software Refresh & Maintenance	13.8	13.7	24.4	12.4	14.9	10.1	10.1	5.1	5.1
Minor Fixed Asset Program	14.5	12.2	8.5	10.9	15.8	17.8	14.6	9.3	7.6
IT Security Program	0.0	0.0	0.0	0.0	0.0	3.9	0.9	1.9	0.4
Development Projects	9.1	4.3	2.8	28.3	61.5	42.9	46.1	15.1	15.0
Cornerstone	79.5	53.7	16.1	2.3	0.0	0.0	0.0	0.0	0.0
Total	**116.9**	**83.9**	**51.8**	**53.9**	**92.2**	**74.7**	**71.7**	**31.4**	**28.1**

1.1 Categories of Costs

Capital expenditures fall into four categories of projects or programs: (1) hardware/software refresh and maintenance, (2) minor fixed assets, (3) security and (4) development.

Hardware/software refresh and maintenance programs ensure the continued operation of the IT application infrastructure and include costs to upgrade existing systems.

Minor fixed assets (MFA) programs ensure the continued operation of the IT hardware infrastructure. They address equipment needs generated by the growth in demand for IT services, capacity limitations and the replacement of end-of-life equipment. Examples of MFA include desktop/notebook computing equipment, field tablet computers, mainframe and storage devices, servers and peripherals, and telecommunication infrastructure including switches, computer-telephony interfaces.

IT security programs ensure the ongoing maintenance and sustainment of existing and newly commissioned security tools, policies, practices, standards and regulatory requirements, such as Bill 198 and NERC CIP.

Development programs ensure the replacement and/or upgrade of end-of-life applications and include investments in new applications to meet business objectives. Applications are replaced when they have become inadequate for current functional needs; where the platform is no longer supported by the vendor; to address legislative changes or market driven initiatives; or to significantly modify the application to better support an evolving business capability. New applications are added to address business needs and to support existing or new business processes**.**

The following general architectural principles apply to all Hydro One IT applications:

- Applications will be “off the shelf” and maintained in a vendor-supported version;
- Custom applications should be migrated to “off the shelf” solutions where possible;
- There will be fewer applications rather than more; and
- Middleware will be used to facilitate application interconnectivity. Hydro One has invested in creating middleware or Service Oriented Architecture (SOA) to enable data integration within and between applications.

This Exhibit details the spending trends for each category of IT capital costs.

2. HARDWARE/SOFTWARE MAINTENANCE AND REFRESH PROGRAMS

Table 2 shows that hardware/software maintenance and refresh capital costs stabilize in the test years 2017 and 2018, and there are no increases in costs to support the hardware/software refresh and maintenance program.

Table 2: Hardware/Software Refresh and Maintenance Program Capital Expenditures ($Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Hardware / Software Refresh & Maintenance	13.8	13.7	24.4*	12.4	14.9	10.1	10.1	5.1	5.1
Total	**13.8**	**13.7**	**24.4***	**12.4**	**14.9**	**10.1**	**10.1**	**5.1**	**5.1**

*This figure includes an unforeseen one-time licensing payment to a vendor.

Hydro One uses approximately 800 business software applications. The software refresh and maintenance program provides needed software vendors' releases, periodic version upgrades, and replacements of activity-focused applications. Software and applications are replaced or upgraded to ensure vendor support and compatibility with current IT environment. Funding decisions are based on and trends reflect software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives.

3. MINOR FIXED ASSETS

The replacement of aging hardware (such as personal computers, servers and storage) is based on the age and the nature of the applications running on the hardware. Equipment may be upgraded, or improvements may be made to extend hardware lifecycle. Hydro One's strategy is to minimize the costs of ownership, ensure operations risk is at an acceptable level, and maintain function and security. MFA costs are broken down into the categories shown in Table 3.

Table 3: Minor Fixed Asset Program Capital Expenditures ($Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**		**TX Allocation**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2017**	**2018**
Servers and Storage	9.4	3.4	2.1	6.1	6.4	8.0	5.3	4.2	2.8
IT Desktops, Laptops, Tablets, Printers &Plotters	3.2	4.8	4.7	3.7	3.2	5.3	4.5	2.8	2.4
Telecom Infrastructure	1.9	4.0	1.7	1.1	4.2	2.5	2.8	1.3	1.4
Smart Grid[2]	-	-	-	-	2.0	2.0	2.0	1.0	1.0
Total	**14.5**	**12.2**	**8.5**	**10.9**	**15.8**	**17.8**	**14.6**	**9.3**	**7.6**

[2] MFA costs associated with the Smart Grid Program moved into IT starting 2016.

3.1 Servers and Storage

Investments in servers and storage are required to respond to and manage growth in demand for processing and storage capacity and to address end-of-life issues. In determining when equipment requires replacement, functionality and operating and maintenance costs are assessed. Funding varies depending upon hardware lifecycles and business requirements for increased processing capacity. Costs in 2013 and 2014 were low and increased in 2015 as capital work programs were deferred due to the scheduled implementation and stabilization of the customer information system project. Costs in 2016 to 2018 reflect expected equipment lifecycle replacement schedules.

3.2 IT Desktops, Laptops, Tablets, Printers, and Plotters

Desktop and laptop computers are used by most Hydro One office staff. Rugged tablet computers are used by field staff. Tablets are used with geospatial information systems

("GIS") applications for system design work and asset condition assessments. Plotters are used by engineering and operations staff for design work and to plot system maps.

Hydro One's practice is to replace desktop and laptop computers every three to five years, and printers and plotters, every four to five years. The renewal timeline is consistent with industry practice. At times, the refresh cycle has been slightly longer but has not adversely affected functionality and maintenance costs.

Funding for desktops, laptops, tablets, printers, and plotters varies depending upon hardware lifecycles and business needs. Costs in 2016 to 2018 reflect expected equipment lifecycle replacement schedules.

3.3 Telecom Infrastructure

The telecom assets of Hydro One are varied with different installation dates and lifecycles. The business telecom network transmits data required to run business applications. Voice or data network improvements or replacements improve network efficiency and ensure equipment is current and supported by third party vendors. Projects regularly undertaken include rewiring local area networks, replacing end-of-life data network switches and routers, upgrading voice infrastructure, replacing un-interruptible power source systems, and upgrading security solutions for external network interfaces.

For voice and data network equipment, the equipment refresh occurs about every five years. Funding for voice and data networks varies depending upon hardware lifecycles and business needs for increased bandwidth. Costs in 2015 were low as the refresh program was accelerated into 2016. Costs stabilize through the 2017 to 2018 period, reflecting a normalised refresh program covering voice networks, telecom networks, data centers and perimeter security.

3.4 Smart Grid

To support tools that manage and monitor the smart grid program, there are necessary investments in server infrastructure. These costs moved to IT starting in 2016.

4. IT SECURITY

Table 4 shows the initiatives that will be undertaken to remediate and improve security capabilities based on lessons learned from past incidents, audit reviews, and industry practice and to implement a holistic risk-based security policy and associated standards.

Table 4: Security Program Capital Expenditures ($Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
IT Security Operations	0.0	0.0	0.0	0.0	0.0	3.0	0.0	1.5	0.0
Data Security	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.4	0.4
Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**3.9**	**0.9**	**1.9**	**0.4**

4.1 IT Security Operations

This initiative is a one-time investment in 2017 to consolidate Hydro One’s enterprise IT and power systems IT environments into one environment for the purposes of security monitoring. This will simplify proactive monitoring, security incident management and situational awareness of IT threats seven days a week, 24 hours a day, 365 days a year.

4.2 Data Security

This initiative improves the data security through a piloted data loss prevention solution to monitor data being emailed, printed, uploaded to the internet or downloaded to a thumb drive. Starting in 2017, as part of this investment there will be a full rollout of the piloted solution. This investment is also required to complete an annual application security review by a third party vendor. The application security review annually selects an application such as SAP, to assess the code of practice application and coding security requirements.

5. DEVELOPMENT PROJECTS

Hydro One's business technology roadmap identifies the sequence and timing of key IT projects and spending. Costs for IT development projects reflect this strategy and are detailed in Table 5.

Table 5: IT Development Projects Capital Expenditures ($Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2017**	**2018**
Work Management & Mobility*	0	0	0	9.9	27	10	6	5	3
Enterprise GIS Program	5.7	4.3	0.6	0	1	3	2.6	1.5	1.3
Engineering Design Transformation	0	0	0	0	0	3.4	1.3	1.7	0.6
Information Rights Management	0	0	0	0	0	0	2.1	0	1
Corporate Performance Reporting	0	0	0	0.8	0	0	4.5	0	2.2
Enterprise Content Management –Project	0	0	0	0	0	0	2	0	1
Enterprise Content Management – Program	0	0	0	0	0	0	1	0	0.5
E-Signature	0	0	0	0	0	0	1	0	0.5
HR Operations Process Optimization	0	0	0	0	0	0	1	0	0.5
Success Factors Onboarding	0	0	0	0	0	0	1.5	0	0.8
Strategic Sourcing	0	0	0	0	0	2.7	0	1.4	0
Hydro One Website Re-design	0	0	0	0	0	2.1	1.5	1	0.8
SAP Treasury	0	0	0	0	0	0	3	0	1.5
SAP EHS Implementation	0	0	0	1.3	2.3	0.2	1	0.1	0.5
Project and Portfolio Management Tool	0	0	0	0	0	1.5	1.5	0.7	0.8
Asset Analytics Risk Factor	0	0	0	0	0	4.4	0	2.2	0
SAP Fixed Asset & Settlement	0	0	0	0	0	3	0	1.5	0
Other Historical Projects (pre-2017)	3.4	0	0	3	7.7	0	0	0	0
Dx IT Projects**	0	0	2.2	13.3	23.5	12.6	16.1	0	0
Total	**9.1**	**4.3**	**2.8**	**28.3**	**61.5**	**42.9**	**46.1**	**15.1**	**15**

* Previously referred to as "Field Work Force Optimization & Mobile IT".
** These projects are Hydro One distribution-related only.

The existing processes and applications used to manage work within the provincial lines, stations and forestry organizations involve significant manual effort and paper processing. This creates inefficiencies, time delays and data inaccuracies. This work needs to be scheduled, dispatched, executed and reported through a standard set of technologies across all of these lines of business within Hydro One. The existing applications used by the provincial lines organization to schedule, dispatch and report work lacks the functionality and integration to support the productivity gains that are now known to be possible. A project ("Work Management & Mobility") is currently under way for the provincial lines organization.

Building on the results of provincial lines' project, similar investments beginning in 2017 will provide the stations organization with work planning and scheduling capability, with possible migration to SAP mobility and estimating functionality integrated with SAP. The plan also includes an initiative to migrate the forestry organization from its existing legacy system to SAP, and introducing the SAP mobile solution for its field workforce.

5.1 Enterprise GIS Program

Geospatial technology is a key infrastructure that enables a variety of business processes including design, transmission and distribution planning, outage management, work management, real estate and others. Geospatial technology and the underlying connected network model is also a key component required to support the benefits achieved from smart grid initiatives. From a strategic perspective, geospatial technology also facilitates adoption of the utility of the future vision of the smart grid, which relies on outage management and distribution management systems, advanced metering infrastructure, advanced system planning and asset management tools and capital expenditure planning. Enterprise GIS is a foundational technology underpinning this vision.

Existing investments in the enterprise GIS program have enabled the integration of SAP and GIS achieving a synchronized, composite asset registry, including distribution and transmission assets, comprised of SAP and Hydro One's other major asset management systems. The existing GIS infrastructure and software need to be updated to take advantage of new functions and software performance improvements and to help build additional capital improvements. All of the major vendor software components are reaching end-of-life during the planning period, and need to be replaced or upgraded. Hydro One also proposes to address gaps and redundancies in business process to author, maintain and utilize data from the spatial databases.

Enhanced GIS functionality is needed to better support various business operations such as load forecasting, outage management, protection and control needs and support the investments that drive a more reliable network.

5.2 Engineering Design Transformation

This project will replace software in the engineering disciplines such as structural design, distribution design and standards design management. It will use best practices, best-in-class applications, and templates based on accepted standards that are intelligently integrated with other design documents. The enterprise content created from these tools will be migrated into a single engineering enterprise content management ("ECM"); this ECM will be integrated with Enterprise ECM referred to in section 5.5.

5.3 Information Rights Management

This investment will implement set of techniques, methods and technologies that protect sensitive Hydro One data from unauthorized access and meet requirements set by NERC CIP and Bill 198, using a leading information rights management solution. This project will allow information and its controls to be separately created, viewed, edited and distributed, mitigating problems associated with avoiding data loss. In addition, this investment will enhance Hydro One's records management program and enterprise content management system because it will enable the dissemination and destruction of records wherever they are stored.

5.4 Corporate Performance Reporting (CPR)

Currently, Hydro One uses a custom Corporate Performance Reporting (CPR) tool to produce high profile corporate reporting deliverables (executive and corporate scorecards, internal control and corporate governance, OEB transmission and distribution reliability reports, reports to government, customer reports, and industry benchmarking reports). The existing tool was built approximately seven years ago and is still being supported by an external vendor. It continues to incur costs and presents unacceptable business continuity risks due to vendor dependency, lack of vendor resource stability and lack of adequate design and functional documentation. In addition, it is not supported by Corporate IT processes and Service Agreements. To mitigate these risks, the CPR project will transition the current CPR tool functionality and data to Hydro One's enterprise environment.

5.5 Enterprise Content Management Project and Program

Enterprise content management ("Enterprise ECM") at Hydro One is being developed as part of a road map to meet regulatory requirements, specifically, the requirements of the NERC Critical Infrastructure Program ("NERC CIP"), the OEB, and the Ontario Securities Commission. The ECM project is a multi-phase project to implement information governance at Hydro One. Phase A completed the classification of a majority of non-complex unstructured data. Phase B is intended to develop proof-ofconcepts to integrate more complex content into the foundation created within Phase A. Phase C will implement these features including reporting tools. Training is also a key component of the project. The overall goal of the Enterprise ECM project is to effectively use and manage Hydro One's information assets to derive maximum value, while minimizing information-related risks.

The Enterprise ECM program will build on the success of the multiphase ECM project. Current unstructured silos of Hydro One data (such as the growth of SAP content and corporate wide email) are to be brought under a centrally-managed, structured solution to reduce legal risk, increase reliability of content, and increase efficiency of access. Administrative tools will be implemented to measure and ensure user adoption, integrity of the system, and ongoing administration of records management. Training will be provided to yield intended benefits.

5.6 E- Signature

Organizations are increasingly being required to implement e-signature solutions to: (a) automate and expedite business processes, (b) cut operational costs, (c) improve efficiency and collaboration, and (d) address legal compliance and limit liability. This project will implement "electronic signatures" within Hydro One. The electronic signature is a proprietary format used to identify the author(s) of an electronic message. By implementing digital signatures, Hydro One is able to significantly shorten process times while cutting costs and improving collaboration and efficiency.

5.7 HR Operations Process Optimization

This project will improve efficiency and productivity in the human resources functions by implementing a number of enhancements such as the ability to: (a) create a case management / ticket-tracking system for issues; (b) build a knowledge database for staff and self-serve capability for managers and employees; (c) create an automated workflow for all forms; (d) provide mobile access for certain applications; and (e) implement metrics and analytics.

5.8 Success Factors Onboarding

This project will enhance the onboarding process for new staff through SAP Success Factors module and implementation of automated workflows. This includes the design and implementation of interactive/smart forms so that as part of the on-boarding process both employees and managers enter the employees' details, with an automated feed into the SAP human resources system. This will also exist for any employee moves such as promotion, demotion, and transfers.

5.9 Strategic Sourcing

This project will implement a cloud-based strategic sourcing tool for bidding, contract management, spend analytics and supplier information management. Key benefits include increased savings through better unit pricing, increase spend compliance and increased productivity through reduction of legacy technologies and paper processes.

5.10 Hydro One Website Re-design

This project is part of the overall strategy to enhance customer experience. This investment will redesign our existing Hydro One website which serves both transmission and distribution customers. By redesigning the existing website, this will improve customer's perception of Hydro One and improve customer satisfaction with Hydro One. The enhanced website will also be mobile-friendly.

5.11 SAP Treasury

The current Treasury System has reached end of life and maintenance costs will increase cumulatively by 50% each year if Hydro One continues to use the current system. This project will implement SAP Treasury application. Doing so will simplify the application landscape while promoting a solution that integrates more tightly with the existing core SAP solutions. Efficiencies would be gained through reduced interface requirements and real-time data availability.

5.12 Environment Health and Safety System

The environment health and safety ("EHS") investment will complete the replacement of existing customized solutions (e.g. incident claims management and waste management) that support the health, safety and environment ("HS&E") organization. Recent projects have and provide the HS&E organization with standard off-the-shelf SAP solutions to manage incidents, claims, investigations, corrective actions, waste (including PCB) management capabilities and subsequent reporting. They are also eliminating the need for interfaces that currently exist with existing legacy systems.

There were a number of additional requirements identified during the project that could not be accommodated in these projects. They were documented and planned to be addressed in a subsequent initiative. This project is to address all of the outstanding requirements identified by the HS&E organization.

5.13 Project and Portfolio Management

The project and portfolio management tool will be administered by the corporate projects office and used by all IT departments to improve all aspects of the project / program planning and delivery lifecycle. This tool will collect work requests which will then be assessed for architectural and security form, fit and delivery costs and they will be prioritized against the business plan. Once in the execution stage, the tool will identify delivery risks to scope, schedule and costs. Stakeholders will be able to track the status of their requests through to delivery.

5.14 Asset Analytics Risk Factor Upgrades

Asset Analytics ("AA") is a tool used in asset planning and prioritizing asset maintenance and replacement. The asset risk assessment model described in Exhibit B1, Tab 2, Schedule 5 is reflected in the tool. The risk factors in the model have remained unchanged since the initial deployment in early 2013. Staff identified opportunities to improve the existing risk factor calculations as well as a need to implement two additional risk factors. These improvements to the number of risk factors and the quality of the risk factor scores will enhance and improve investment planning decisions. The project scope also includes the implementation of a data bridge between AA risk factors and the asset investment planning ("AIP") enterprise risk model. This bridge will automate, standardize, and expedite a data correlation process that is currently manual and subjective. Overall, the goal is to further improve service delivery reliability and customer satisfaction via improved data quality for investment decision-making.

5.15 SAP Fixed Asset and Settlement

This project will significantly reduce the number of project cost settlement errors that currently occur each month. In addition to extending the financial system batch run time, these errors result in someone having to manually review and fix these project settlement errors. There will be significant efficiencies gained by implementing this enhancement as it will reduce the manual effort required each month to fix these project settlement errors.

5.16 Dx IT Projects

The proposed IT projects is for funding the development and tools that will benefit customers related to billing, contact center, collections and portal/website re-design to support the new customer strategy.

FACILITIES AND REAL ESTATE

1. INTRODUCTION

This Exhibit addresses facilities and real estate's ("F&RE") capital expenditures to acquire (own or lease) and maintain Hydro One's office space and service centres and capital expenditures to enhance transmission security infrastructure.

Table 1: Total Facilities and Real Estate, and Transmission Security Infrastructure Capital Expenditures ($Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Facilities & Real Estate	22.7	16.5	29.4	29.3	31.8	36.8	41.8	18.4	20.9
Tx Security Infrastructure	2.7	0.7	4.3	11.8	6.7	0.0	0.0	0.0	0.0
Total	**25.4**	**17.2**	**33.7**	**41.1**	**38.5**	**36.8**	**41.8**	**18.4**	**20.9**

2. FACILITIES & REAL ESTATE

Table 2 presents the total F&RE capital expenditures for the historic, bridge and test years as well as the 2017-2018 transmission-allocated amounts.

Table 2: Total Facilities and Real Estate Capital Expenditures ($Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Major Capital	20.8	15.5	25.9	26.7	30.0	35.0	40.0	17.5	20.0
Minor Fixed Assets	1.9	1.0	3.5	2.6	1.8	1.8	1.8	0.9	0.9
Total	**22.7**	**16.5**	**29.4**	**29.3**	**31.8**	**36.8**	**41.8**	**18.4**	**20.9**

The primary driver for the increase in costs is the need to provide suitable space and to accommodate the staff resources and equipment required to handle the substantial growth in core Sustainment, Development and Operations work programs over this period (as described in Exhibits B1 and C1). These expenditures encompass the refurbishment, acquisition and/or development of field facilities.

2.1 Major Capital Expenditures

The F&RE major capital program allows for the provision of workspace for administrative facilities, the Ontario Grid Control Centre in Barrie, and service centre facilities.

Key program work activities include:

- addressing company accommodation requirements in terms of new buildings, buildings additions and major facility renovations;
- replacing major building components including roof structures, windows, heating, ventilating and air conditioning ("HVAC") systems and other structural elements and building systems;
- dealing with environmental issues that may arise such as mould; and
- water treatment upgrades to improve quality and reliability of water supply, including conversions to municipal supply.

The capital work program includes improvements to existing facilities, building additions and new facilities in line with the company's operational requirements and responding to work program space demands. This program also focuses on ensuring critical facility structural and other building improvements to enhance the life of assets.

Maintaining building and site assets in a condition that ensures their long-term viability, while meeting the workspace needs of employees, on a day-to-day basis, is critical for the successful completion of a variety of corporate work activities. Hydro One contracts to have regular inspections of administrative and service centre sites across the province, ensuring critical building/site components (such as HVAC systems, roof, windows) are routinely inspected and major structural and related problems are identified. From the inspection recommendations, component replacement work is scheduled on a priority basis. Planned and corrective replacement of these critical components varies year over year based on recommendations from the facility service providers.

The facilities infrastructure base is dominated by buildings and associated systems and components that are at or reaching the end of their asset life cycle. Approximately 40% of administrative and service centre facilities are estimated to be more than 40 years old. The aging facilities asset base, in conjunction with work program demands and operational needs of the business units, requires capital investment in order to continue to provide adequate workspace accommodation. These requirements will be addressed on a priority basis and/or as opportunities emerge.

2.2 Minor Fixed Assets

Investments in minor fixed assets pertain to office workstations and furniture that are beyond the end of their normal service life and need to be replaced. Table 2 shows the estimated minor fixed assets expenditures in the test years 2017-2018. This includes replacement of furniture and office equipment related to new and renovated space accommodation requirements.

3. SECURITY INFRASTRUCTURE INVESTMENTS

Table 3: Transmission Security Infrastructure Capital Expenditures ($ Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Tx Security Infrastructure	2.7	0.7	4.3	11.8	6.7	0.0	0.0	0.0	0.0
Total	**2.7**	**0.7**	**4.3**	**11.8**	**6.7**	**0.0**	**0.0**	**0.0**	**0.0**

*Spending for security investments from the bridge year onwards is included in the station-centric investments described in Exhibit B1, Tab 3, Schedule 2.

The F&RE major capital program historically also funded security infrastructure investments designed to effectively deter, delay, detect and respond to security threats that target transmission stations. Since 2006, there has been a significant increase in criminal activity aimed at transmission stations. These threats can include copper theft, domestic extremism, and terrorism. Copper thieves typically steal fence grounds, underground grid and live grounds off transformer neutrals as well as other station equipment. There are heightened safety concerns for employees and first responders where tampering with electrically live equipment has occurred. Without the appropriate level of security, the risk to transmission stations will continue with likelihood of severe injury or fatality from the intrusions and the risk of outages impacting local and system reliability.

Funding over the test years has been redirected from the historical asset-centric categories of Sustainment stations capital to integrated station-centric investments as described in Exhibit B1, Tab 3, Schedule 2. This reflects the general shift in planning approach to complete more Sustainment capital investments using integrated approaches.

TRANSPORT, WORK, AND SERVICE EQUIPMENT

1. INTRODUCTION

This Exhibit identifies the transport and work equipment ("TWE") and service equipment capital expenditures for the period 2012 to 2018. The TWE and service equipment program provides vehicle and specialized equipment support to the growing work programs across the organization.

Table 1: Total TWE and Service Equipment Capital Expenditures 2012-2018 ($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**		**TX Allocation**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2017**	**2018**
Transport and Work Equipment	44.4	54.1	61.4	67.2	69.9	64.4	67.3	20.9	21.8
Service Equipment	9.8	8.1	9.7	7.0	6.6	6.1	6.2	3.2	3.2
Total	**54.2**	**62.2**	**71.1**	**74.2**	**76.5**	**70.5**	**73.5**	**24.1**	**25.0**

2. TRANSPORT AND WORK EQUIPMENT

The decrease of $5.5 million in capital expenditures in 2017 from the bridge year 2016, as shown in Table 2, is related to the stabilization in work programs for the forestry mechanical brushing program and provincial lines apprenticeship programs. As of December 31, 2015, Hydro One has approximately 7,800 TWE units with an original capital value ("OCV") of $603 million, of which approximately 650 units require replacement each year. Fleet capital requirements are primarily based on industry standards for life cycle expectancy, the remaining capital value, and operating cost drivers. Light vehicles are replaced after six years or 180,000 km, service trucks are replaced after six years or 300,000 km, and work equipment is replaced after eight to ten years or 400,000 km.

Table 2: TWE Capital Expenditures
2012–2018 ($ Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Transport and Work Equipment	44.4	54.1	61.4	67.2	69.9	64.4	67.3	20.9	21.8
Total	**44.4**	**54.1**	**61.4**	**67.2**	**69.9**	**64.4**	**67.3**	**20.9**	**21.8**

The objective of the TWE replacement program is to promote an orderly system of purchasing and funding a standardized fleet replacement process, to plan for future transportation requirements as well as identify the need to increase overall fleet size. The TWE replacement program annually analyzes five-year cycles for capital investment requirements and maintains a safe and efficient fleet. It is critical to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. The fleet capital program, on an annual basis, is evaluated against the business plan and is subject to the work program prioritization and forecasting process. Business cases for the program are prepared and approved and the equipment is strategically procured through a tendering process.

The TWE replacement program reviews:

- equipment capital forecast;
- equipment productivity, functionality, and future requirements;
- equipment standards, equipment age, mechanical condition, kilometers traveled and cost per kilometer, downtime, and repair time;
- safety/risk;
- work programs, evaluating staff and equipment complement;

- tendered procurement process;
- fleet's original capital value and net book value;
- historical and future utilization; and
- strategic procurement.

The guidelines for vehicles considered for replacement are based on vehicles meeting predetermined criteria including, but not limited to: manufacturer's life expectancy, average cost per kilometer, regulated maintenance standards and safety/risk. Hydro One takes advantage of discounts by establishing purchasing cycles with manufacturers. As vehicles reach the targeted criteria, a vehicle maintenance evaluation is performed and, in some cases, the unit may be reassigned to other functions with "low usage" requirements.

The replacement program measures the age and value of the fleet and meets the requirements and due diligence of a well-managed utility fleet.

The benefits of Hydro One's replacement program include:

- maximum safety, productivity and utilization;
- maximizing equipment availability;
- optimizing repair time, and fleet complement; and
- maximizing efficiency and life cycle benefits.

2.1 2012 to 2018 Period Analysis

As noted in Exhibit C1, Tab 5, Schedule 1, the overall size of Hydro One's fleet was adjusted to approximately 7,800 vehicles and other equipment in 2015 to match the work programs. TWE expenditures are forecasted to be $64.4 million in 2017 based on the number of vehicles required to execute the planned work programs.

In 2016, the capital expenditure primarily reflects the amount required to maintain core fleet requirements ($49.8 million). Of the total $69.9 million, $10.5 million is required to support the increased provincial lines apprenticeship program requirements, $3.0 million for capital adjustments based on U.S. currency fluctuation, $3.0 million progressive payment for replacement of a helicopter, and completion of a fleet telematics project ($3.6 million).

In 2017, TWE capital expenditures of $64.4 million include the requirement for core TWE replacements ($50.8 million), incremental TWE requirements for the forestry mechanical brushing program ($2.1 million), incremental TWE requirements for the increase in provincial lines apprenticeship program ($2.9 million), capital adjustments based on $USD currency fluctuation ($3.5 million), final payment for replacement of a helicopter ($3.6 million) and provincial lines and forestry TWE service equipment replacements ($1.5 million). These expenditures include a final payment for one new helicopter.

In 2018, TWE capital expenditures of $67.3 million include the requirement for core TWE replacements ($51.8 million), incremental TWE requirements for the forestry mechanical brushing program ($2.2 million), incremental TWE requirements for the increase in provincial lines apprenticeship program ($4.4 million), capital adjustments based on U.S. currency fluctuation ($3.7 million), progressive payment for replacement of a helicopter ($3.6 million), and provincial lines and forestry TWE service equipment replacements ($1.6 million).

2.2 Capital vs. Operating Leases

The evaluation of leasing as a financial alternative to the approved capital program was evaluated during the 2003 strategic sourcing initiative. The evaluation included the review of both capital and operating leases and the total operating costs. The risks and benefits generated by leasing were evaluated and it was decided the risks outweighed the modest benefits. The results therefore indicated that leasing was not cost effective.

The requirement for short term rentals (as distinct from long-term rentals) is recognized and is included with fleet operating expenses in Exhibit C1, Tab 5, Schedule 1.

2.3 Procurement Initiatives

In order to effectively manage costs over the test years, the fleet services function follows capital procurement objectives for material and service acquisitions which include:

- profile the commodities, collect and analyze cost drivers;
- analyze the supply market;
- develop a strategy for sourcing;
- select the suppliers through a rigorous competitive procurement process; and
- conduct negotiations.

These procurement initiatives have allowed Hydro One to lock in pricing for three-year terms with an option of renewal for a fourth and fifth year with preferred vendors.

3. SERVICE EQUIPMENT

Table 3 identifies the expenditures for service equipment for the 2012 to 2018 period.

Table 3: MFA Service Equipment Capital Expenditures
2012 – 2018 ($ Millions)

Description	Historical Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Service Equipment	9.8	8.1	9.7	7.0	6.6	6.1	6.2	3.2	3.2
Total	**9.8**	**8.1**	**9.7**	**7.0**	**6.6**	**6.1**	**6.2**	**3.2**	**3.2**

Minor fixed assets for service equipment consists of capital items of $2,000 or more, required by Hydro One staff to carry out construction and maintenance work programs. Capital items less than $2,000 are expensed to OM&A. Minor fixed asset expenditures for service equipment are required to replace equipment at end of life, replace technologically obsolete service equipment when new standards and safer work practices come into effect, and provide for sufficient levels of new service equipment consistent with the work program.

Purchases in this category include specialized transportation equipment for off-road work sites and mobile equipment required to carry out a variety of work.

Specialized transportation equipment used for both distribution and transmission includes items such as all-terrain vehicles, boats, barges, snowmobiles and related accessories. Service equipment also includes: mobile cranes, stringing equipment, Schnabel cars, and float trailers.

Mobile equipment includes oil tankers, de-gassifiers, and dry air machines required for transformer maintenance, SF6 gas carts required for the maintenance of SF6 breakers, and a variety of other equipment necessary to analyze, test, and carry out construction and maintenance associated with the work program.

Year-over-year changes in spending are largely the result of the evolving needs of distribution and transmission work programs. Forecasted expenditures for the test years show as lower than historical levels because funds were redirected to the TWE replacement program expenditures reflected previously in Table 2.

COMMON ASSET ALLOCATION

1. INTRODUCTION

This evidence will discuss the nature of Common Fixed Assets ("Shared Assets") and the method by which the costs of these assets are assigned to the Distribution and Transmission business units.

Similar to the corporate common costs discussed in Exhibit C1, Tab 6, Schedule 1, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment ("T&WE").

2. SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (6.3% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this exhibit. Table 1 summarizes the total gross fixed assets and identifies the proportion of allocated shared assets.

Table 1: Summary of Gross Fixed Assets as at December 31, 2015 ($ Million)

	Transmission	Distribution	Total
Total Fixed Assets	15,092.6	10,093.3	25,185.9
Shared Assets (in Total)	679.7	912.1	1591.8
Shared Asset %	**42.7%**	**57.3%**	**100%**

Shared assets are sub-divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2 shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value as of December 31, 2015.

Table 2: Details of Shared Net Fixed Assets as at December 31, 2015 ($ Million)

Asset	Gross Asset Value	Accumulated Depreciation	Net Book Value
Shared Major Assets	793.3	411.7	381.6
Shared Minor Assets	798.5	478.7	319.8
Total Shared Assets	**1591.8**	**890.4**	**701.4**

3. ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, shared assets are not directly attributable to either the Transmission or Distribution business units. In addition, from year to year, the use of these shared assets may change, based upon changes in the underlying transmission and distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their use and that the costs are apportioned appropriately amongst the business units.

In 2008, Hydro One commissioned a study by Black & Veatch (B&V) (Formerly R.J. Rudden Associates) to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The B&V study resulted in the allocation of shared assets based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

Hydro One has accepted the approach of the B&V study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate Decisions: RP-2005-0020/EB-2005-0378/EB-2007-0681, and in the subsequent Transmission rate Decisions: EB-2006-0501/EB2008-0272/EB-2010-0002/EB-2012-0031/EB-2014-0140. The methodology was also used in Hydro One's latest application for Distribution Rates for 2015 to 2019 (EB-2013-0416).

The appropriate use of the common asset allocation methodology for the 2017 to 2018 test years has been reviewed and confirmed by B&V in 2016, and is provided as Attachment 1 to this Exhibit.

Due to the significance of Cornerstone, software that integrates work management, finance, supply chain and customer service, as a Shared Asset, Hydro One has developed transfer price charge rates to allocate a portion of the revenue requirement related to certain Shared Assets to the Telecom and Remotes businesses. The methodology and impact of the transfer price charges are described in more detail in Attachment 1 to this Exhibit.

Hydro One has used the approved B&V Asset Allocation methodology in this proposed application and Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2015.

Table 3: Hydro One Common Asset Allocation as at December 31, 2015 ($ Million)

Total Gross Value All Hydro One Transmission & Distribution Assets $25,186.9 million			
Transmission (Total)	$15,092.6	Distribution (Total)	$10,093.3
Transmission (Direct)	$14,412.9	Distribution (Direct)	$9,181.2
Transmission (Common)	$679.7	Distribution (Common)	$912.1

REVIEW OF SHARED ASSETS ALLOCATION (TRANSMISSION) – 2015

BLACK & VEATCH PROJECT NO. 188588

PREPARED FOR

Hydro One Networks Inc.

4 MAY 2016

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LIST OF TABLES

I. Summary

A. BACKGROUND AND PURPOSE

Black & Veatch Canada Company ("Black & Veatch") is pleased to submit to Hydro One Networks Inc. ("Hydro One") this Report which describes our Review of Shared Assets Allocation (Transmission) – 2015. This Report describes the review that Black & Veatch performed, at the request of Hydro One, of its allocation of the costs of Shared Assets in its 2017-2018 Transmission Rates filing before the Ontario Energy Board ("OEB"). In this Report, "cost" is the original cost (i.e., gross book value) derived as of June 30, 2015.

In 2005, Black & Veatch recommended, Hydro One adopted, and the OEB accepted a methodology for Hydro One to allocate the costs of Shared Assets between its Distribution and Transmission businesses, and issued our *Report on Shared Assets Methodology Review* dated June 15, 2005 ("2005 Assets Report"). Black & Veatch's objective in allocating the Shared Assets was to ensure that the allocation was reasonable, reflected best practices and was consistent with the allocation of common corporate costs, as discussed in Black and Veatch's *Review of Allocation of Common Corporate Costs (Transmission)*- dated May 4, 2016 ("2015 Common Corporate Costs Report-Transmission").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with reports issued, as follows:

Table 1 - History of Black & Veatch's Cost Allocation Reviews for Hydro One

BLACK & VEATCH REVIEW/ASSET VALUES	HYDRO ONE FILING	BLACK & VEATCH REPORT
2006 Review 12/31/2005	2006 Distribution Rates	Report on Common Assets Methodology 2006 dated May 31, 2006
2008 Review 12/31/2007	2008 Transmission Rates	Report on Common Assets Methodology 2008 dated September 10, 2008
2009 Review (Distribution) 12/31/2008	2010/2011 Distribution Rates	Report on Common Assets Allocation- 2009 dated June 29, 2009
2009 Review (Transmission) 12/31/2008	2011/2012 Transmission Rates	Report on Common Assets Allocation (Transmission) - 2010 dated February 26, 2010
2011 Review (Transmission) 12/31/2010	2013/2014 Transmission Rates	Report on Shared Assets Allocation (Transmission) 2012 dated February 1, 2012
2013 Review (Distribution) 12/31/2012	2015-2019 Distribution Rates	Report on Shared Assets Allocation (Distribution) 2013 dated September 19, 2013
2014 Review (Transmission) 12/31/2012	2015-2016 Transmission Rates	Report on Shared Assets Allocation (Transmission) 2013 dated March 17, 2014

The OEB-accepted methodology has been applied by Hydro One to its Business Plan for 2015-20 ("BP 2015-20") data for its 2017-2018 Transmission Rates filing. This Report describes the "Review of Shared Assets Allocation (Transmission)" that Black & Veatch performed, at Hydro One's request, of its application of the methodology to its BP 2015-20, and presents Black & Veatch's conclusions.

In its 2017-2018 Transmission Rates filing, Hydro One has allocated 42.7% of the cost of the Shared Assets to its Transmission business and 57.3% to its Distribution business. These ratios are similar to the ratios used in its 2015/2016 Transmission Rates filing which allocated 42.3% to its Transmission business and 57.7% to its Distribution business.

In addition, Hydro One has developed transfer price charge rates for its Telecom and Remotes businesses, to be used in allocating to those businesses a portion of the total revenue requirement related to the Shared Assets (e.g., depreciation expense and return). In the past, before Cornerstone assets had been placed in service, no Shared Assets were assigned to Telecom or Remotes. There is no impact from the divestiture of Brampton on the Shared Asset Allocation as no costs or transfer prices rates were charged to Brampton as Brampton did not use these assets.

B. TYPES OF SHARED ASSETS

Hydro One provided Black & Veatch with a list of the Shared Assets, by Asset Group and Asset Subgroup, as shown in Table 2.

Table 2 – Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	▪ Software ▪ Buildings and Telecommunications equipment
Minor Fixed Assets ("MFA")	▪ Aircraft ▪ Computer Hardware ▪ Office equipment ▪ Service equipment- Miscellaneous ▪ Service equipment- Measurement and Testing ▪ Service equipment- Storage ▪ Tools ▪ Transportation Work Equipment ▪ Transportation Work Equipment- Power equipment

If an asset was estimated to be used at least 95% in either Transmission or Distribution, the cost of that asset was removed from Shared Assets and directly assigned to that business.

C. SUMMARY OF APPROACH

Allocation of Asset Costs to Transmission and Distribution

A cost driver was assigned to each asset (i.e., a building within Major Assets), asset type (i.e., Pickup

Trucks within Transportation Work Equipment) or Asset Subgroup, based on discussions with Hydro One personnel to ascertain what cost driver was most closely related to the usage of the asset or the Asset Subgroup. The cost drivers used to allocate the Shared Assets were selected from among, or derived from, the cost drivers used to allocate the costs of the common corporate functions and services. The specific steps used for each Asset Group and Subgroup are discussed below. The amounts allocated to Transmission and Distribution are summarized in Table 2.

Development of Transfer Price Charge Rates for Telecom and Remotes

The transfer price charge rates represent the usage of the Shared Assets by Hydro One's Telecom and Remotes businesses. Our approach to developing the transfer price charge rates was as follows:

- The portion of each asset that should be allocated to Telecom and Remotes based on the appropriate cost driver was determined.
- The total dollar amount allocated to Telecom, representing the Shared Asset cost, was computed for each asset by multiplying the Telecom share of usage by the asset cost; these dollar amounts were summed and divided by the category total cost to determine the Telecom share for the category. The same was done for Remotes. Table 3 presents the resulting Telecom and Remotes transfer price charges.
- The percentages should be applied to each component of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return), to compute the dollar amount charged to Telecom and Remotes. The amounts charged to Telecom and Remotes should be applied to reduce the revenue requirement recovered from rate payers of the Transmission and Distribution businesses.

  For example, the study determined that Telecom uses 0.51% (Table 3) of the shared Major Assets owned by Hydro One Networks. As such, 0.51% of the revenue requirement associated with major assets is charged to Telecom. The revenue requirement calculated for HONI will include 100% of the assets, however, the other revenues received from the Hydro One Inc. subsidiaries will reduce the revenue requirement which is used to derive the tariff rates.

II. Descriptions of Asset Groups

A. MAJOR ASSETS

Software

Most of the software included in Shared Assets was for Hydro One's Cornerstone project, an enterprise-wide system to support work management, asset management, human resources, financial and other functions. These costs were allocated using cost drivers that reflect the activities supported. Infrastructure costs related to each phase were allocated based on the activities those phases support. For example, the portion of the Cornerstone project related to Human Resources was allocated based on headcount.

Buildings and Telecommunications Equipment

Each asset included in Buildings and Telecommunications Shared Assets was discussed with Hydro One personnel, and allocated using one of the following methods:

- **Specific estimation for a building.** For example, Sudbury Service Centre has estimated usage of Transmission-20% and Distribution-80%.
- **Direct assignment based on type of usage**. For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2011-2014 and determined that Fleet usage was Transmission- 32.39% and Distribution- 67.61%; therefore the costs for buildings used for Fleet were allocated using these percentages.

  Buildings used for Training were allocated using the cost driver Headcount.
- **Cost drivers based on proxy.** For example, Buildings used to manage both Distribution and Transmission projects are allocated using the cost driver *Program Project Costs*, developed as part of the 2015 Common Corporate Costs Report- Transmission study.

B. MINOR FIXED ASSETS

Each component of Minor Fixed Assets includes many individual items. Black & Veatch reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft –** Helicopter and supporting components. Usage was based on an analysis of time charges (which are recorded to time sheets concurrently with usage) for years 2011-2014.
- **Computer Hardware –** Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using a cost driver based on the number of *Workstations* (50% weight) and the cost driver *Headcount* (50% weight).
- **Office equipment –** Includes office furniture and other office equipment. Allocated using the cost driver *Headcount*.
- **Service equipment - Miscellaneous** – Includes miscellaneous equipment. Allocated using *Total Common Costs* cost driver, developed as part of the 2015 Common Corporate Costs Report- Transmission study.
- **Service equipment- Measurement and Testing** – Includes Meters, Splicers etc. used for Distribution. Directly assigned to *Distribution*.

- **Service equipment- Storage** – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on spending for *Operating and Maintenance costs and Capital spending*.
- **Tools** – Includes Rental tools. Allocated Distribution-20% / Transmission-80% reflecting estimated usage based on information as to which business units are renting the tools.
- **Transportation & Work Equipment** – Includes primarily Vehicles. Allocated using the cost driver "Fleet", which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2011-2014. Except for items representing less than 1.0% of cost, the usage for all of the Transportation & Work Equipment Shared Assets were recorded on time sheets and included in the computation of the Fleet cost driver.

The results are summarized in Table 2.

Summary of Results

Table 3 presents the allocation of Shared Assets to Hydro One's Transmission and Distribution businesses.

Table 3 - Summary of Shared Assets Allocation

Type	Total	Transmission	Distribution	Transmission %	Distribution %
Major Assets					
Software	$ 508.9	$ 254.7	$ 254.2	50.0%	50.0%
Building/Telecom	$ 134.7	$ 66.7	$ 68.0	49.5%	50.5%
Total	$ 643.6	$ 321.4	$ 322.2	49.9%	50.1%
Minor Assets					
Aircraft	$ 24.1	$ 17.5	$ 6.7	72.4%	27.6%
Computer Hardware	$ 98.0	$ 52.1	$ 45.8	53.2%	46.8%
Office Equipment	$ 12.9	$ 6.9	$ 6.0	53.2%	46.8%
Service - Miscellaneous	$ 6.9	$ 3.0	$ 3.8	44.2%	55.8%
Service - Measurement and Testing	$ 16.3	$ -	$ 16.3	0.0%	100.0%
Service - Storage	$ 2.7	$ 1.4	$ 1.3	52.1%	47.9%
Tools	$ 11.9	$ 9.5	$ 2.4	80.0%	20.0%
Transportation Work Equipment	$ 618.0	$ 200.2	$ 417.8	32.4%	67.6%
Total	$ 790.8	$ 290.6	$ 500.2	36.7%	63.3%
Total - All Shared Assets	$ 1,434.3	$ 612.0	$ 822.4	42.7%	57.3%

Table 4 presents the Shared Assets transfer price charges for Telecom and Remotes.

Table 4 - Transfer Price Charges for Other Businesses

Asset Group	Telecom	Remotes
Major Assets	0.51%	0.23%
Minor Fixed Assets	0.50%	0.14%
Total - All Shared Assets	0.40%	0.15%

Expert Evidence Statement from Black & Veatch Canada Company

This Statement is provided in compliance with Ontario Energy Board ("Board") Rule 13A, regarding the reports listed below ("Reports") dated May 4, 2016, prepared by Black & Veatch Canada Company ("Black & Veatch").

Reports:

- Review of Allocation of Common Corporate Costs (Transmission) – 2015
- Review of Shared Assets Allocation (Transmission) – 2015
- Review of Overhead Capitalization Rates (Transmission) – 2017-2018

Consultant:
Black & Veatch Canada Company
11401 Lamar Avenue
Overland Park, KS 66211

Black & Veatch, and its affiliate Black and Veatch Management Consulting LLC, provide strategic, economic and management consulting specializing in energy matters, in areas such as utility cost allocation and ratemaking, economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support, and technical analysis.

Qualifications:

The lead experts on this project were:

David DesLauriers

Mr. DesLauriers is a highly experienced Director in Black & Veatch's Rates & Regulatory Services group and specializes in regulated interstate transmission pricing and wholesale electric market policy matters. He delivers a unique blend of regulatory policy acumen and practical rate setting experience to provide highly effective and supportable ratemaking and regulatory solutions to his clients. Mr. DesLauriers has advised numerous midstream energy utilities on rates and regulatory policy for the past 24 years. His areas of expertise include: electric transmission cost of service and rate design, wholesale electric market design policy and operational topics, Federal Energy Regulatory Commission (FERC) policy matters, regulatory due diligence (M&A) and compliance with FERC regulation. His clients include Regional Transmission

Organizations and Independent System Operators, transmission owning energy companies (regulated and non-regulated) and industry stakeholder groups involved in FERC regulatory policy. Mr. DesLauriers led the common cost allocation study conducted for Kinder Morgan Inc. in 2009-2010 timeframe and testified before FERC on common cost allocation (IS09-437).

Russell Feingold

Mr. Feingold leads Black & Veatch's Rates & Regulatory Services group and has over 40 years of experience in the utility industry, the past 37 years of which have been in the field of utility management and economic consulting. Specializing in the utility industry, he has advised and assisted utility management, and industry trade and research organizations in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. He has prepared and presented expert testimony before numerous utility regulatory bodies, including the Ontario Energy Board, and has spoken widely on issues and activities dealing with the costing, pricing, and marketing of utility services. Mr. Feingold has led cost allocation review projects for Hydro One Networks Inc. related to the allocation of common corporate service costs, for Union Gas Limited and Enbridge Gas Distribution related to their regulated and unregulated underground storage operations, and for Union Gas Limited related to its Dawn to Trafalgar gas transmission system, and its corporate shared services functions.

John Taylor

During his 12 year career as a consultant to utilities Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He also has experience in asset and corporate valuation, the application of real options analysis, and various risk management techniques. Mr.

Taylor has also been involved in the sale of generating assets, supporting due diligence efforts and regulatory approval processes. He has filed testimony as an expert witness on class cost of service studies and on the appropriate use of statistical analysis during audit testing.

Instructions Provided:

The instructions provided to Black & Veatch in preparing the Report were:

- Recommend a best practice methodology to distribute Hydro One Inc.'s Common Corporate costs among the business units that use the functions and services. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology.
- Prepare a Report of the recommended Common Corporate Costs Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Identify the functions and services included in the Common Corporate costs.
- Identify activities that are performed in order to provide the functions and services included in the Common Corporate costs.
- Determine which Common Corporate functions can distribute cost directly, which units can have cost distributed using time studies and which units require allocations using drivers and why.
- Propose and analyze all drivers used for allocation.
- Propose, analyze and perform all time studies required.
- Distribute the annual budgeted costs for years 2017-2021 to perform each function and service among the activities required to perform it, based on time and/or cost studies.
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not.
- Prepare responses to Interrogatories from Interveners during a rate application relating to the proposed Cost Allocation methodology.
- Be available to testify to the proposed methodology during a future rate application.
- Prepare final reports for Common Corporate Costs allocation reflecting the current Business Plan and including both the Distribution and Transmission businesses, to be submitted in Cost of Service applications.
- In support of the successful Proponent's work, Hydro One's management will respond to all requests for basic information and/or supporting documentation.

Expert Evidence Statement from Black & Veatch Canada Company

Basis of Evidence:

The basis for the evidence is set forth in the Reports themselves.

Context of Evidence:

This evidence is not provided in response to another expert's evidence. In 2004, Black & Veatch (formerly R.J. Rudden Associates) was engaged by Hydro One to recommend a best practice methodology to distribute the costs of providing Shared Services, between its Transmission and Distribution businesses and other businesses. Black & Veatch recommended the methodology, which was adopted by Hydro One and accepted by the Board in its EB- 2006-0501 Decision with Reasons, dated August 16, 2007. The accepted methodology has been reviewed and updated by Black & Veatch and accepted by the Board as part of subsequent Transmission and Distribution rate filings EB-2007-0681, EB-2008-0272, EB-2009-0096, EB-2010-0002, EB-2012-0031, EB-2013-0416, and EB-2014-0140. To remain consistent with the Board's approved methodology, a similar review and update process has been done as part of this filing.

Confirmation:

The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature: David F DesLauriers

Name of Expert: Black & Veatch Canada Company

By David DesLauriers, Director, Black & Veatch Management Consulting LLC

Date: May 5, 2016

FORM A

Proceeding: EB-2016-0160

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is David DesLauriers. I live at Westborough, in the state of Massachusetts.

2. I have been engaged by or on behalf of Hydro One Networks, Inc. to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date May 5, 2016

David J. DesLauriers

Signature

OVERHEAD CAPITALIZATION RATE

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In its April 9, 2010 Decision on Hydro One's 2010 and 2011 distribution rates (EB-2009-0096), the Board accepted the methodology, recommendations and the allocation of costs from a study by Black & Veatch (B&V,formerly RJ Rudden Associates), which derived an overhead capitalization rate for Hydro One Distribution's common corporate costs. The accepted methodology was used in the 2013-2014 transmission rate application EB-2012-0031 and the 2015-2016 transmission rate application EB 2014-0140.

Hydro One Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support and removes the need for an e-factor adjustment.

Hydro One proposes that the resulting overhead capitalization rate, as calculated in the B&V study in 2015, continues to be a reasonable method of distributing common corporate costs to capital projects for transmission rates in 2017 and 2018. Hydro One’s submissions in this Application reflect this overhead capitalization rate.

Table 1 summarizes the overhead capitalization rates and amounts as reviewed by B&V.

Table 1: Overhead Capitalization Rates & Amounts

Overhead Cost Category	Test Years (%)		Test Years ($millions)	
	2017	2018	2017	2018
Capitalized Administrative & General Costs[1]	10%	9%	$102.5	$104.4
Capitalized Operating Costs[2]	3%	4%	$30.7	$30.2
Total	13%	12%	$133.2	$134.7

[1] Administrative & General Costs include all common corporate functions and services costs
[2] Operating costs include asset management, operating and customer care management costs

In its EB-2011-0268 decision, the Board granted Hydro One Transmission approval to adopt United States Generally Accepted Accounting Principles (US GAAP) as its approved basis for rate setting, regulatory accounting and regulatory reporting commencing January 1, 2012. In this decision, the Board also directed Hydro One Transmission to conduct a critical review of its then current and proposed capitalization practices. The Board stated that the review should not be a benchmarking study, but should include information, for comparison purposes, on what US transmitters typically capitalize and capitalization methodologies employed by other transmitters. (See page 13 of the decision.)

A summary of the results of this review (which covered both transmission and distribution entities) was filed as part of Hydro One Transmission's 2013-2014 transmission rate application (EB-2012-0031). The same methodologies were used to allocate Common Corporate Costs and Other O&M costs to the transmission overhead capitalization rate in 2015 and 2016 Transmission rate application (EB-2014-0140). It was determined to be appropriate by the intervenors and Board Staff who participated in the Settlement Conference, and was accepted by the Board in its Decision.

As documented in the review report, Hydro One critically reviewed its cost capitalization policy with a particular focus on the capitalization of overhead and indirect costs. In its review, Hydro One found that its treatment of overhead capitalized is generally consistent with other major US and Canadian industry participants. Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One's industry research of other Canadian and US utilities.

Hydro One also concluded that its overhead and indirect cost capitalization methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with: (a) legacy Canadian and existing US GAAP; and (b) regulatory principles, including the key goals of achieving intergenerational equity and avoiding cross subsidization.

REVIEW OF OVERHEAD CAPITALIZATION RATES (TRANSMISSION) – 2017-2018

BLACK & VEATCH PROJECT NO. 188588

PREPARED FOR

Hydro One Networks Inc.

4 MAY 2016

BLACK & VEATCH
Building a world of difference.

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I. Overview

A. INTRODUCTION

Black & Veatch Canada Company ("Black & Veatch") is pleased to submit to Hydro One Networks Inc. ("Hydro One") this Report which describes our Review of Overhead Capitalization Rates (Transmission) - 2017-2018. The Overhead Capitalization Rates ("OH Cap Rates") developed by Hydro One are percentages that are applied to the cost of Transmission and Distribution capital expenditures; the results are the amounts of Common Corporate Costs that are capitalized to those capital expenditures for the year.

The methodology was developed for Hydro One by Black & Veatch, first presented in our report *Distribution Overhead Capitalization Rate Method* dated May 20, 2005 and accepted by the Ontario Energy Board ("OEB").

The OEB-accepted methodology for development of the OH Cap Rates has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with reports issued, as follows:

Table 1 - History of Black & Veatch's Cost Allocation Reviews for Hydro One

BLACK & VEATCH REVIEW	HYDRO ONE FILING	BLACK & VEATCH REPORT
2006 Review	2006 Transmission Rates	Transmission Overhead Capitalization Rate Method dated April 30, 2006
2008 Review	2008 Transmission Rates	Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010 dated September 10, 2008
2009 Review (Distribution)	2010/2011 Distribution Rates	Review of Overhead Capitalization Rates dated June 29, 2009
2009 Review (Transmission)	2011/2012 Transmission Rates	Review of Overhead Capitalization Rates (Transmission) – 2011/2012 dated February 26, 2010
2011 Review (Transmission)	2013/2014 Transmission Rates	Review of Overhead Capitalization Rates (Transmission)– 2013-2014 dated February 1, 2012
2013 Review (Distribution)	2015-2019 Distribution Rates	Review of Overhead Capitalization Rates (Distribution)– 2015-2019 dated September 19, 2013
2013 Review (Transmission)	2015/2016 Distribution Rates	Review of Overhead Capitalization Rates (Transmission)– 2015-2016 dated March 17, 2014

Hydro One computed the **Transmission OH Cap Rate to be 13% for 2017 and 12% for 2018** (*Appendix A, row 92*). The calculation of the rates is described in Section II of this report and shown in Appendix A.

Based on the work performed, Black & Veatch believes that Hydro One's implementation of the Overhead Capitalization Rate methodology and computation of the Transmission OH Cap Rates for 2017-2018 are appropriate and conform to the OEB-accepted methodology.

B. BACKGROUND

Hydro One's capital spending program is a major focus for the utility in terms of time and cost. Transmission Capital spending is budgeted to be approximately $1.1 billion annually in 2017-2018, each year representing approximately 10% of Transmission Net utility plant.

Most of Hydro One's capital program is performed by Hydro One employees, and not contracted out. Hydro One's capital program requires significant support from all areas of the utility, including engineering, management, administration and infrastructure resources. These resources support Transmission Operations and Maintenance ("Tx OMA") and Transmission Capital Expenditures work.

C. CRITERIA FOR COST ALLOCATION METHODS

The portion of Common Corporate Costs attributed to Transmission was determined based on the OEB-accepted methodology, as described in the Black & Veatch's *Review of Allocation of Common Corporate Costs (Transmission)*- dated May 4, 2015 ("2015 Common Corporate Costs Report-Transmission").

The Transmission OH Cap Rate is used to distribute the Transmission portion of Common Corporate Costs, between Transmission OMA and Transmission Capital Expenditures. Following are the criteria that Black & Veatch used in selecting and evaluating methods to develop the OH Cap Rates methodology:

- The method should be based on cost causation. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the costs that has been incurred.
- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is benefits received (i.e., allocated to the business that received the benefits).
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- If the method uses estimates, results should be unbiased and reasonably consistent with the results that would be obtained from using actual data.

D. DESCRIPTION OF OH CAP RATE METHOD

Approximately $115 million of labour costs, representing approximately 36% of the annual total Common Corporate Costs (and approximately 50% of annual labour costs), were directly assigned between OMA and capital based on a time study performed for the four-week period ending June 12, 2015 ("2015 Time Study"). The 2015 Time Study included the following departments:

Table 2 – Departments in Time Study

Operations	**Customer and Corporate Relations**
■ Distribution Asset Management	■ Customer Care Services
■ Planning and Optimization	■ Customer Strategy and Conservation
■ Reliability, Strategies, and Compliance	■ Customer Program Delivery
■ System Planning	■ Key Account Management
■ Network Connections and Development	■ VP Customer Service
■ Network Operations	■ Meter to Bill
■ Transmission Asset Management	
■ VP Planning	
■ EVP Operations	

A properly performed time study measures cost causation and is widely accepted as a basis for assigning costs. Hydro One personnel administered the 2015 Time Study using the same design and communication material designed by Black & Veatch and utilized in the time study that occurred in 2013. Black & Veatch's responsibilities included reviewing time study results and the consolidation of the results, and confirming the completeness of the time study and its consistency with the study design. The methodology was the same as used in prior time studies conducted by Black & Veatch for Hydro One. Black & Veatch found that the 2015 Time Study was properly conducted, and therefore is a proper basis to determine the portion of the costs of the participating departments to be capitalized to Transmission capital expenditures.

While the remaining Common Corporate Costs departments can determine with reasonable accuracy the portions of time spent on Transmission, Distribution and the other business units, they are unable to determine with reasonable accuracy the time spent on OMA versus capital projects. Therefore, the amount of costs to be capitalized must be computed using allocators based on cost causation or benefits received.

In traditional utility cost allocation studies, administrative and general costs are allocated based on one or more factors such as Labor costs, OMA, Investment in Plant or a weighted combination of two or more. Black & Veatch considered the following two bases for allocating Common Corporate Costs between OMA and capital projects:

- **Labor Content Method-** Labor Content of Transmission (Tx) OMA versus Tx capital expenditures
- **Total Spending Method-** Total Spending on Tx OMA versus Tx capital expenditures

  The Common Corporate Costs to be allocated are causally related to both Labor Content and Total Spending. Therefore the OH Cap Rate method for Common Corporate Costs recommended by Black & Veatch uses a weighting of 50% Labor Content and 50% Total Spending, as there is no evidence that either the Labor Content method or the Total Spending method is meaningfully more appropriate.

- The formula for Transmission (Tx) Labor Content is:

  Tx Labor Content = Tx Labor $ in Tx Capital Expenditures / (Labor $ in Tx Capital Expenditures + Labor $ in Tx OMA)

- The formula for Tx Total Spending is:

  Tx Total Spending = Tx Capital Expenditures / (Tx Capital Expenditures + Tx OMA) The table below shows the results of the computations for 2017-2018.

Table 3 – Total Spending Method Labour and Spending Breakdown

PORTION OF COMMON CORPORATE COSTS SERVICES CAPITALIZED- TRANSMISSION	2017	2018
Labor Content- Capital	66.97%	68.31%
Total Spending- Capital	76.47%	77.34%
50/50 Average	70.55%	71.72%

Sensitivity Analysis

As a sensitivity analysis, Black & Veatch analyzed two sensitivity cases - the highest Labor Content weight considered (75%) and the lowest Labor Content weight considered (25%). The results, shown below, indicate the total OH Cap Rates would not change materially.

Table 4 – Sensitivity Analysis

CASES	LABOR CONTENT / TOTAL SPENDING	TRANSMISSION-2017		TRANSMISSION-2018	
		% costs Capitalized	2017 OH Cap Rate	% costs Capitalized	2018 OH Cap Rate
Recommended	50%/50%	70.55%	12.71%	71.72%	12.20%
High Labor Case	75%/25%	68.23%	12.35%	69.40%	11.86%
Low Labor Case	25%/75%	72.75%	13.05%	73.92%	12.53%

Black & Veatch also considered the following:

1. The same rate is applied to capitalized assets regardless of their actual usage of Common Corporate Costs services. For example, a transformer that is purchased for use in a capital project from a pre-approved vendor requires very little of these services, but receives the same rate of overhead capitalization as a project requiring substantial support. In applying the OH Cap Rates, there will be differences compared to performing a specific analysis for each project. However, the Black & Veatch method is appropriate because:
   - Black & Veatch's recommended Labor / Total Content method correctly computes the total Common Corporate Costs dollars to be capitalized, and the amount charged to specific expenditures has virtually no effect on the financial statements or on ratepayers.
   - Most assets purchased for stand-alone use are Minor Fixed Assets and the OH Cap Rates are computed without them, and not applied to these minor assets. Other assets (i.e., non-Minor Fixed Assets) are usually parts of larger projects, therefore the use of average OH Cap Rates is appropriate, because larger expenditures are more likely to have an average usage of Shared Services.
   - It is impractical to perform an analysis for each project.
2. The OH Cap Rates are developed based on the weighted Labor Content and Total Spending, but are applied to Total Capital Cost.

It is appropriate to compute the total costs to be capitalized based on the weighted Labor Content / Total Spending. Once the amount to be capitalized is computed, it can be applied based on either Total Cost or Labor Content. Black & Veatch recommends stating the capitalization rate based on Total cost, and applying it to Total cost dollars, as Hydro One has done, because it is easier to plan and implement based on Total cost than Labor content.

Black & Veatch believes that allocating Common Corporate Costs to capital expenditures based on 50% Labor Content/50% Total Spending is the most appropriate method for Hydro One, and is consistent with industry practice and with the nature of the costs being capitalized.

E. USE OF BUDGETED NUMBERS

The OH Cap Rates are developed based on Business Plan numbers and other estimates. Hydro One reviews and adjusts the OH Cap Rates quarterly to reflect changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up (in-year) to reflect actual results. Therefore, no adjustment is needed in subsequent years.

II. Computation of Transmission OH Cap Rate

This Section presents, as an example, the computation of the Transmission OH Cap Rate for 2017. The calculation of the rate uses the same method for all years in BP 2017-2018.

A. FORMULA

The following formula is used to compute the 2017-2018 Transmission OH Cap Rates:

a. *Transmission OH Cap Rate*= (Capitalized Transmission CCC-A&G Costs + Capitalized Transmission CCC-Operating Costs) / Transmission Capital Expenditures

Note: A&G = Administrative & General

Where

b. *Capitalized Transmission CCC-A&G Costs* = Transmission CCC-A&G Costs capitalized = (Transmission Labor Content Ratio X 50% + Transmission Total Spending Ratio X 50%) X Transmission CCC-A&G Costs

c. *Transmission CCC-A&G Costs* = Total Transmission CCC Costs less Transmission CCC-Operating Costs departments

d. *Capitalized Transmission CCC-Operating Costs* = Transmission CCC-Operating Costs capitalized, based on the results of the 2015 Time Study

e. *Transmission CCC-Operating Costs* = The budgets for departments, included in the 2015 Time Study

f. *Transmission Capital* = Cost of Transmission capital expenditures supported by Common Corporate Costs (i.e., CCC-A&G Costs plus CCC-Operating Costs); also, total cost of Transmission capital expenditures to which the Transmission OH Cap Rate is applied

g. *Transmission Labor Content Ratio* = Transmission Labor $ in Transmission Capital Expenditures / (Labor $ in Transmission Capital Expenditures + Labor $ in Transmission OMA)

h. *Transmission Total Spending Ratio* = Transmission Capital Expenditures / (Transmission Capital Expenditures + Transmission OMA)

These terms are further discussed below.

B. RECOMMENDED METHOD

This section discusses the method recommended by Black & Veatch to compute the Transmission OH Cap Rate. References below are to Appendix A, and the amounts and percentages cited are for 2017. The calculations use projected data. Because the methodology includes a true-up at the end of the year (Section I.E), the amounts recorded by Hydro One reflect actual data.

1. TRANSMISSION CAPITAL

(Appendix A, rows 1-8)

Transmission Capital (Formula f in Section II.A) represents the cost of Transmission business Capital Expenditures that are supported by Transmission business CCC activities (CCC-A&G activities and CCC-Operating activities), and is the total cost of Transmission business Capital Expenditures to which the Transmission OH Cap Rate is applied. Transmission Capital equals total spending for Transmission Capital Expenditures reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little CCC-A&G or CCC-Operating support.
- Capitalized Overhead is removed to avoid redundancy.
- Capital Contributions by Customers are added because the CCC-A&G and CCC-Operating effort required is related to gross capital cost, not net capital cost.
- Removal Costs are added because removal of capital assets requires support from CCC-A&G and CCC-Operating.

2. TRANSMISSION SPENDING FOR OMA

(Appendix A, rows 9-15)

Transmission Spending for OMA is used in computing the portion of Total Spending (capital plus OMA) related to capital (rows 39-43). The amounts are based on the BP 2017-2018, with adjustments to remove those costs which are included in Applicable CCC-A&G costs (row 31).

3. APPLICABLE TRANSMISSION CCC-A&G COSTS

(Appendix A, rows 16-31)

Applicable Transmission CCC-A&G Costs (Formula c) (row 31) represents the Transmission CCC-A&G Costs subject to capitalization, and equals total Common Corporate Costs distributed to the Transmission Business in the Common Corporate Costs Model, adjusted as follows:

- Transmission CCC-Operating Costs (Formula e) are removed because the capitalization ratios for those departments were determined in the 2015 Time Study.
- Transmission Facilities costs that are removed from the CCC-A&G Costs, relating to Operations facilities, are added back, because they are used to support activities that support Capital Expenditures.
- Transmission CCC-A&G Costs for the following departments that do not support capital expenditures are removed: Inergi- Customer Support Operations (CSO), Inergi-ETS to support CSO Applications, Inergi-ETS to support market transition costs and Inergi- Settlements (Note- No costs of CSO or Inergi-ETS-CSO were allocated to Transmission in the Corporate Common Costs model.)

4. TRANSMISSION LABOR CONTENT- CAPITAL RATIO

(Appendix A, rows 33-37)

Transmission Labor Content-Capital Ratio is the portion of total Transmission labor costs included in Transmission Capital Expenditures (Formula g). The Labor $ on Rows 34-35 were developed by Hydro One. The Labor $ are fully burdened labor costs (salary plus benefits).

5. TRANSMISSION TOTAL SPENDING- CAPITAL RATIO

(Appendix A, rows 39-43)

Transmission Total Spending-Capital Ratio is the portion of Transmission total spending included in Transmission Capital Expenditures (Formula h). In the formula, Transmission spending for OMA (row 40) is from row 15 and Transmission spending for capital expenditures (row 41) is from row 8.

6. CAPITALIZED TRANSMISSION CCC-A&G

Capitalized CCC-A&G Costs (Formula b) is the portion of Transmission CCC-A&G Costs to be capitalized. The portion of Transmission CCC-A&G Costs to be capitalized (row 49) is the average of Transmission Labor Content-Capital Ratio (from row 37) and Total Spending Capital Ratio (from row 43), using the appropriate weights (rows 46-47),. This portion is multiplied by the Applicable CCC-A&G Costs (row 31) to compute Capitalized CCC-A&G Costs (row 53).

7. CAPITALIZED TRANSMISSION CCC-OPERATING

(Appendix A, rows 62-81)

Capitalized Transmission CCC-Operating Costs (Formula d) represents the amount of Transmission CCC- Operating Costs capitalized to Transmission Capital Expenditures. The 2015 Time Study showed that 38.9% of Asset Development and Management time, 22.2% of Network Operations time and 0.4% of Customer Care time, are related to Transmission Capital Expenditures. These percentages are applied to the BP 2017-2018 annual budgeted amounts for those groups, and the results are the amounts of CCC-Operating Costs to be capitalized (rows 72-76).

8. TRANSMISSION OH CAP RATE

(Appendix A, rows 83-92)

The Transmission OH Cap Rate (Formula a) equals (A) the sum of items 6 and 7 above, divided by (B) Capital spending. The Transmission OH Cap Rates for 2017-2018 (row 92) are in the table below.

TRANSMISSION OVERHEAD	2017	2018
Rate	13.0%	12.0%

Appendix A - Transmission Overhead Capitalization Rates – BP 2017-2018

	($ millions)	2017	2018
1	**Capital Expenditures**		
2	Total capexp	1076.1	1122.2
3	Less: Minor fixed assets	(34.3)	(33.6)
4	Less: Capitalized overhead	(133.2)	(134.7)
5	Less: Capitalized interest	(46.4)	(49.7)
6	Add: Capital contributions	132.7	130.4
7	Add: Removal costs	53.4	69.2
8		1048.2	1103.9
9	**OM&A**		
10	Total OM&A	431.4	425.5
11	Less: CCFS costs	(122.4)	(122.2)
12	Less: Facility costs	(24.3)	(24.9)
13	Less: Asset Management costs (excl. facility costs)	(74.0)	(73.4)
14	Add: Capitalized overheads	133.2	134.7
15		343.8	339.8
16	**Capitalized CCFS Costs**		
17	Total Costs per CCCM	196.4	195.6
18	Less: Asset Development and Management	(35.8)	(35.1)
19	Less: Customer Care/CBR	(3.5)	(3.5)
20	Less: Operator	(34.6)	(34.8)
21	Net CCFS Costs	122.4	122.2
22	Add: Facility costs	24.3	24.9
23			
24	Less operating-type CCFS costs:		
25	Inergi - CSO	0.0	0.0
26	Inergi - ETS CSO Apps	0.0	0.0
27	Inergi - ETS Market Ready	(1.0)	(1.0)
28	Inergi - Settlements	(0.4)	(0.4)
29		(1.4)	(1.4)
30			
31	Applicable CCFS costs	145.3	145.6
32			
33	Portion capitalized based on labour content:		
34	Labour in OM&A	186.8	184.4
35	Labour in capexp	359.3	373.8
36		546.2	558.2
37	% capexp	65.8%	67.0%
38			
39	Portion capitalized based on total spending:		
40	OM&A	343.8	339.8
41	Capexp	1048.2	1103.9
42		1392.1	1443.7
43	% capexp	75.3%	76.5%
44			
45	Weighting:		
46	Labour content	50.0%	50.0%
47	Total spending	50.0%	50.0%
48			
49	Portion capitalized based on w eighting of tw o methods	70.5%	71.7%
50			
51	Applicable CCFS costs	145.3	145.6
52			
53	Capitalized CCFS costs	102.5	104.4
54			
55			

Appendix A - Transmission Overhead Capitalization Rates – BP 2017-2018

		2017	2018
56	Network Asset Management Costs (Tx + Dx):	2017	2018
57	Asset Management (excl. facility costs)	48.5	47.5
58	Operating	52.8	53.0
59	Customer Care Management/CBR	45.0	44.9
60		146.3	145.4
61			
62	Portion capitalized (per time study):		
63	Asset Management (excl. facility costs)	38.9%	38.6%
64	Operating	22.2%	22.2%
65	Customer Care Management/CBR	0.4%	0.4%
66			
67	Portion to OM&A (per time study):		
68	Asset Management (excl. facility costs)	35.0%	35.3%
69	Operating	43.4%	43.4%
70	Customer Care Management/CBR	7.5%	7.5%
71			
72	Capitalized Asset Management costs:		
73	Asset Management (excl. facility costs)	18.9	18.3
74	Operating	11.7	11.8
75	Customer Care Management/CBR	0.2	0.2
76		30.7	30.2
77			
78	Non-Capitalized Asset Management costs:		
79	Asset Management (excl. facility costs)	17.0	16.8
80	Operating	22.9	23.0
81	Customer Care Management/CBR	3.4	3.4
82		43.3	43.1
83	**Overhead Capitalization Rate**		
84	Capitalized CCFS costs	102.5	104.4
85	Capitalized Asset Management costs	30.7	30.2
86		133.2	134.7
87		(133.2)	(134.7)
88	Capexp	1,048.2	1,103.9
89			
90	Calculated overhead capitalization rate	12.7%	12.2%
91			
92	Rounded	13.0%	12.0%

Expert Evidence Statement from Black & Veatch Canada Company

This Statement is provided in compliance with Ontario Energy Board ("Board") Rule 13A, regarding the reports listed below ("Reports") dated May 4, 2016, prepared by Black & Veatch Canada Company ("Black & Veatch").

Reports:

- Review of Allocation of Common Corporate Costs (Transmission) – 2015
- Review of Shared Assets Allocation (Transmission) – 2015
- Review of Overhead Capitalization Rates (Transmission) – 2017-2018

Consultant:
Black & Veatch Canada Company
11401 Lamar Avenue
Overland Park, KS 66211

Black & Veatch, and its affiliate Black and Veatch Management Consulting LLC, provide strategic, economic and management consulting specializing in energy matters, in areas such as utility cost allocation and ratemaking, economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support, and technical analysis.

Qualifications:

The lead experts on this project were:

David DesLauriers

Mr. DesLauriers is a highly experienced Director in Black & Veatch's Rates & Regulatory Services group and specializes in regulated interstate transmission pricing and wholesale electric market policy matters. He delivers a unique blend of regulatory policy acumen and practical rate setting experience to provide highly effective and supportable ratemaking and regulatory solutions to his clients. Mr. DesLauriers has advised numerous midstream energy utilities on rates and regulatory policy for the past 24 years. His areas of expertise include: electric transmission cost of service and rate design, wholesale electric market design policy and operational topics, Federal Energy Regulatory Commission (FERC) policy matters, regulatory due diligence (M&A) and compliance with FERC regulation. His clients include Regional Transmission

Organizations and Independent System Operators, transmission owning energy companies (regulated and non-regulated) and industry stakeholder groups involved in FERC regulatory policy. Mr. DesLauriers led the common cost allocation study conducted for Kinder Morgan Inc. in 2009-2010 timeframe and testified before FERC on common cost allocation (IS09-437).

Russell Feingold

Mr. Feingold leads Black & Veatch's Rates & Regulatory Services group and has over 40 years of experience in the utility industry, the past 37 years of which have been in the field of utility management and economic consulting. Specializing in the utility industry, he has advised and assisted utility management, and industry trade and research organizations in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. He has prepared and presented expert testimony before numerous utility regulatory bodies, including the Ontario Energy Board, and has spoken widely on issues and activities dealing with the costing, pricing, and marketing of utility services. Mr. Feingold has led cost allocation review projects for Hydro One Networks Inc. related to the allocation of common corporate service costs, for Union Gas Limited and Enbridge Gas Distribution related to their regulated and unregulated underground storage operations, and for Union Gas Limited related to its Dawn to Trafalgar gas transmission system, and its corporate shared services functions.

John Taylor

During his 12 year career as a consultant to utilities Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He also has experience in asset and corporate valuation, the application of real options analysis, and various risk management techniques. Mr.

Taylor has also been involved in the sale of generating assets, supporting due diligence efforts and regulatory approval processes. He has filed testimony as an expert witness on class cost of service studies and on the appropriate use of statistical analysis during audit testing.

Instructions Provided:

The instructions provided to Black & Veatch in preparing the Report were:

- Recommend a best practice methodology to distribute Hydro One Inc.'s Common Corporate costs among the business units that use the functions and services. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology.
- Prepare a Report of the recommended Common Corporate Costs Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Identify the functions and services included in the Common Corporate costs.
- Identify activities that are performed in order to provide the functions and services included in the Common Corporate costs.
- Determine which Common Corporate functions can distribute cost directly, which units can have cost distributed using time studies and which units require allocations using drivers and why.
- Propose and analyze all drivers used for allocation.
- Propose, analyze and perform all time studies required.
- Distribute the annual budgeted costs for years 2017-2021 to perform each function and service among the activities required to perform it, based on time and/or cost studies.
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not.
- Prepare responses to Interrogatories from Interveners during a rate application relating to the proposed Cost Allocation methodology.
- Be available to testify to the proposed methodology during a future rate application.
- Prepare final reports for Common Corporate Costs allocation reflecting the current Business Plan and including both the Distribution and Transmission businesses, to be submitted in Cost of Service applications.
- In support of the successful Proponent's work, Hydro One's management will respond to all requests for basic information and/or supporting documentation.

Expert Evidence Statement from Black & Veatch Canada Company

Basis of Evidence:

The basis for the evidence is set forth in the Reports themselves.

Context of Evidence:

This evidence is not provided in response to another expert's evidence. In 2004, Black & Veatch (formerly R.J. Rudden Associates) was engaged by Hydro One to recommend a best practice methodology to distribute the costs of providing Shared Services, between its Transmission and Distribution businesses and other businesses. Black & Veatch recommended the methodology, which was adopted by Hydro One and accepted by the Board in its EB- 2006-0501 Decision with Reasons, dated August 16, 2007. The accepted methodology has been reviewed and updated by Black & Veatch and accepted by the Board as part of subsequent Transmission and Distribution rate filings EB-2007-0681, EB-2008-0272, EB-2009-0096, EB-2010-0002, EB-2012-0031, EB-2013-0416, and EB-2014-0140. To remain consistent with the Board's approved methodology, a similar review and update process has been done as part of this filing.

Confirmation:

The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature: David F DesLauriers

Name of Expert: Black & Veatch Canada Company

By David DesLauriers, Director, Black & Veatch Management Consulting LLC

Date: May 5, 2016

FORM A

Proceeding: EB-2016-0160

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is David DesLauriers. I live at Westborough, in the state of Massachusetts.

2. I have been engaged by or on behalf of Hydro One Networks, Inc. to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date May 5, 2016

David J. DesLauriers

Signature

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2017 OR 2018

1. SUSTAINING CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 2)

1.1 Stations

		2017	2018
Air Blast Circuit Breaker Replacement Projects			
S01	Beck #1 SS	5.9	12.0
S02	Beck #2 TS	29.8	14.9
S03	Bruce A TS	13.8	19.7
S04	Bruce B SS	0.9	24.6
S05	Cherrywood TS	1.4	3.8
S06	Lennox TS	26.1	16.9
S07	Richview TS	16.9	13.5
Station Reinvestment Projects			
S08	Beach TS	16.5	15.9
S09	Centralia TS	12.5	6.2
S10	Dryden TS	16.2	0.1
S11	Elgin TS	22.6	17.8
S12	Espanola TS	3.0	0.0
S13	Gage TS	1.2	12.4
S14	Kenilworth TS	5.6	11.2
S15	Nelson TS	10.9	20.2
S16	Palmerston TS	8.8	11.6
S17	Wanstead TS	13.7	14.3
Integrated Station Component Replacement Projects			
S18	Alexander SS	14.4	8.8
S19	Allanburg TS	4.7	1.0
S20	Aylmer TS	3.5	0.0
S21	Barrett Chute SS	9.3	3.9
S22	Birch TS	12.1	13.8
S23	Bronte TS	3.7	17.1
S24	Bridgman TS	0.2	3.3
S25	Buchanan TS	4.2	0.0
S26	Cecil TS	9.6	0.0

		2017	2018
S27	Chenaux TS	7.5	2.1
S28	Crawford TS	4.2	0.0
S29	DeCew Falls SS	4.9	0.0
S30	Dufferin TS	6.5	7.4
S31	Ear Falls TS	10.9	0.0
S32	Frontenac TS	3.8	1.5
S33	Hanmer TS	24.4	11.0
S34	Hawthorne TS	1.6	4.3
S35	Horning TS	14.3	14.9
S36	Leaside TS Bulk	5.9	5.6
S37	Leaside TS 27.6 kV	6.3	6.5
S38	Main TS	5.4	8.4
S39	Manby TS	3.1	1.8
S40	Martindale TS	18.6	18.6
S41	Minden TS	4.2	7.0
S42	Mohawk TS	4.6	4.7
S43	N.R.C. TS	7.1	0.7
S44	Pine Portage SS	1.9	5.9
S45	Richview TS	7.3	0.0
S46	Sheppard TS	9.8	9.3
S47	St. Isidore TS	9.1	0.0
S48	Stanley TS	0.5	6.1
S49	Strachan TS	5.1	2.8
S50	Strathroy TS	5.3	0.0
Transmission Station Demand and Spares			
S51	Demand Capital – Power Transformers	8.0	8.2
S52	Minor Component Demand Capital	4.7	4.7
S53	Operating Spare Transformer Purchases	8.2	8.3
Protection, Control and Monitoring			
S54	Transformer Protection Replacement	4.6	4.6
S55	Replace Legacy SONET Systems	2.1	5.3
S56	Physical Security for Critical Stations (non CIP-014)	5.0	5.0
S57	CIP V6 Transient Cyber Assets & Removable Media	2.0	10.0
S58	PSIT Cyber Equipment EOL	5.0	6.0
S59	CIP-014 Physical Security Implementation	6.0	6.0
S60	NERC CIP V6 CAPEX - Low Impact Facilities	5.0	5.0
Transmission Site Facilities			
S61	Transmission Site Facilities	6.7	6.7

1 **1.2 Lines**

		2017	2018
Transmission Line Refurbishment Projects			
S62	Line Refurbishment Project - C22J/C24Z/C21J/C23Z	18.5	2.5
S63	Line Refurbishment Project - D2L Dymond x Upper Notch	8.4	0.0
S64	Line Refurbishment Project - C1A/C2A/C3A	1.8	3.5
S65	Line Refurbishment Project - N21W/N22W	4.1	11.9
S66	Line Refurbishment Project - B5G/B6G	4.4	11.4
S67	Line Refurbishment Project - D2L Upper Notch x Martin River	18.3	21.1
S68	Line Refurbishment Project - B3/B4	0.9	6.4
S69	Line Refurbishment Project - A8K/A9K	0.4	6.6
S70	Line Refurbishment Project - A7L/R1LB and 57M1	0.9	20.5
S71	Line Refurbishment Project - K1/K2	0.9	7.4
S72	Line Refurbishment Project - E1C	0.9	12.8
S73	Line Refurbishment Project - D6V/D7V	2.6	5.7
S74	Line Refurbishment Project - D2H/D3H	0.9	12.5
Overhead Lines Component Replacement Programs			
S75	Wood Pole Replacements	35.3	35.3
S76	Steel Structure Coating	42.5	54.4
S77	Steel Structure Foundation Refurbishments	7.8	7.8
S78	Shieldwire Replacements	7.0	7.1
S79	Insulator Replacements	63.9	61.4
S80	Transmission Lines Emergency Restoration	8.7	8.8
Secondary Land Use and Recoverable Projects			
S81	Gordie Howe International Bridge (Recoverable)	12.7	12.5
S82	Manvers – Lafarge Aggregate Pit (Recoverable)	1.0	3.8
Underground Cable Projects			
S83	H7L/H11L Cable Replacement	1.3	21.1

Summary – Sustaining Capital

	2017	2018
Total Sustaining Capital Projects & Programs Listed Above	740.0	785.6
Sustaining Capital Projects & Programs Less than $3M	74.8	87.2
Total Gross Sustaining Capital	**814.8**	**872.8**
Less Capital Contribution	*(38.0)*	*(30.7)*
Total Net Sustaining Capital (per Exhibit B1-3-2)	**776.8**	**842.1**

2. DEVELOPMENT CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 3)

		2017	2018
2.1	**Inter-Area Network Transfer Capability**		
D01	Clarington TS: Build new 500/230kV Station	68.6	14.8
D02	Nanticoke TS: Connect HVDC Lake Erie Circuit	5.0	13.0
D03	Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade	2.5	8.0
D04	East-West Tie Expansion: Station Work	3.0	30.0
D05	Milton SS: Station Expansion and Connect 230kV Circuits	2.0	5.0
2.2	**Local Area Supply Adequacy**		
D06	Galt Junction: Install In-Line Switches on M20D/M21D Circuits	3.6	0.1
D07	York Region: Increase Transmission Capability for B82V/B83V Circuits	22.6	0.2
D08	Hawthorne TS: Autotransformer Upgrades	8.0	5.8
D09	Brant TS: Install 115kV Switching Facilities	5.0	6.0
D10	Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits	2.4	4.2
D11	Southwest GTA Transmission Reinforcement	0.9	5.0
D12	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits	4.0	20.0
2.3	**Load Customer Connection**		
D13	Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D	10.0	5.9
D14	Supply to Essex County Transmission Reinforcement	33.0	31.4
D15	Horner TS: Build 230/27.6kV Transformer Station	16.0	13.0
D16	Lisgar TS: Transformer Upgrades	10.3	2.5
D17	Seaton MTS: Rebuild 230 kV Circuit	3.3	3.0
D18	Hanmer TS: Build 230/44kV Transformer Station	9.5	18.5
D19	Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits	23.0	17.0
D20	Toyota Woodstock: Upgrade Station	3.0	2.5
D21	Enfield TS: Build 230/44kV Transformer Station	10.0	15.0
D22	TransCanada: Energy East Pipeline Conversion	1.9	10.2
2.4	**Protection and Control for Distributed Generation**		
D23	Protection and Control Modifications for Distributed Generation	6.0	5.5

		2017	**2018**
2.5	**Risk Mitigation**		
D24	Nanticoke TS: New Station Service Supply	10.0	0.0

Summary – Development	**2017**	**2018**
Total Development Projects & Programs Listed Above	**263.6**	**236.6**
Development Projects & Programs Less than $3 M	**27.4**	**33.3**
Total Gross Development Capital (per Exhibit B1-3-3)	**291.0**	**269.9**
Less Capital Contribution	*(94.7)*	*(99.7)*
Total Net Development Capital (per Exhibit B1-3-3)	**196.4**	**170.2**

3. OPERATIONS CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 4)

3.1 Grid Operations and Control Facilities

		2017	2018
O01	Integrated System Operations Centre - New Facility Development	4.2	10.5

3.2 Operating Infrastructure

		2017	2018
O02	Station Local Control Equipment Sustainment	3.6	3.7
O03	Grid Control Network Sustainment	5.8	3.0

Summary – Operations	2017	2018
Total Operations Projects & Programs Listed Above	13.6	17.2
Operations Projects & Programs Less than $3 M	11.7	13.5
Total Operations Capital (per Exhibit B1-3-4)	**25.4**	**30.8**

4. COMMON CORPORATE CAPITAL AND OTHER COSTS (EXHIBIT B1, TAB 3, SCHEDULES 5-8)

Transmission Allocation of Capital Corporate Costs and Other Costs		2017	2018
4.1 Information Technology			
IT1	Hardware/Software Refresh and Maintenance	5.1	5.1
IT2	MFA Servers and Storage	4.2	2.8
IT3	Work Management and Mobility	5.0	3.0
4.2 Other			
CC1	Real Estate Field Facilities Capital	18.4	20.9
CC2	Transport & Work Equipment	20.9	21.8
CC3	Service Equipment	3.2	3.2

Summary - Capital Common Corporate Costs & Other Costs	2017	2018
Total Capital Common Corporate Costs Projects listed above	56.8	56.8
Capital Common Corporate Costs Projects less than $3 M	20.8	22.3
Transmission Allocation of Capital Common Corporate Costs & Other Costs (per Exhibit B1-3-5)	**77.6**	**79.1**

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Air Blast Circuit Breaker Replacement – Beck #1 SS
Targeted Start Date: Q2 2017
Targeted In-service Date: Q4 2019
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Beck#1 SS that are in need of replacement due to deteriorated condition, equipment performance, and obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Sir Adam Beck #1 SS is a switching station connecting Ontario Power Generation's ("OPG's") Sir Adam Beck Generating Station I to the 115kV transmission system. The facility was originally placed in-service in 1947 and many of the station assets are in need of major work to maintain reliability. The existing 115kV bus at Beck #1 SS is also currently restricting generation output and will require upgrading to higher capacity to remove these restrictions.

There are two ABCBs at Sir Adam Beck #1 SS that are up to 44 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable than a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Beck#1 SS.

This project entails:

- Replacement of two ABCBs, associated breaker disconnect switches, station DC systems;
- Upgrades to the station's 115kV bus to remove capacity restrictions and protection and control equipment; and
- Removal of four free standing transformers along with the entire high pressure air system, which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To maintain system reliability and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	6.4	12.9	25.9
Operations, Maintenance & Administration and Removals	(0.5)	(0.9)	(1.8)
Gross Investment Cost	**5.9**	**12.0**	**24.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.9**	**12.0**	**24.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Air Blast Circuit Breaker Replacement – Beck #2 TS
Targeted Start Date: Q1 2016
Targeted In-Service Date: Q4 2021
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Beck#2 TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Sir Adam Beck #2 TS is a critical network station connecting Ontario Power Generation's ("OPG's") Sir Adam Beck Generating Station II to the 230kV transmission system. The facility was originally placed in-service in 1955 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are twenty ABCBs at Sir Adam Beck #2 TS that are up to 48 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Beck#2 TS.

This project entails:

- Replacement of twenty ABCBs, associated breaker disconnect switches, station AC/DC systems;
- Upgrades to protection and control equipment needed to meet NPCC standards; and
- Removal of forty sets of free standing transformers, along with the entire high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	30.4	15.4	93.4
Operations, Maintenance & Administration and Removals	(0.6)	(0.5)	(2.7)
Gross Investment Cost	**29.8**	**14.9**	**90.7**
Capital Contribution	0.0	0.0	0.0
Net Capital Investment Cost	**29.8**	**14.9**	**90.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document
Sustaining Capital - Stations

Investment Name: Air Blast Circuit Breaker Replacement – Bruce A TS
Targeted Start Date: Q4 2013
Targeted In-Service Date: Q2 2019
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Bruce A TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Bruce A TS is a critical network station connecting the Bruce Power Nuclear Generation Station to the 500kV and 230kV transmission network. The Bruce A TS 230 kV switchyard was originally placed in-service in the 1976 and many of the station assets are in need of major work to sustain their functionality. The existing breakers and strain buses are also restricting generation in the area due to their limited short circuit capability. Due to the stations criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are sixteen 230kV ABCBs at Bruce A TS that are 44 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Bruce A TS.

This project entails:

- Replacement of sixteen circuit breakers, associated breaker disconnect switches, instrument transformers, protection and control systems, and other associated auxiliary components; and
- Removal of thirty-two sets of free standing transformers along with the high pressure air system which will no longer be required.

To address the short circuit interrupting capability the station strain buses will be uprated and supporting structures will be reinforced or replaced, as required, to withstand the mechanical and thermal effects of the higher short circuit current.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, address the insufficient short circuit capability, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	13.8	19.7	105.9
Operations, Maintenance & Administration and Removals	0.0	0.0	(1.0)
Gross Investment Cost	**13.8**	**19.7**	**104.9**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**13.8**	**19.7**	**104.9**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Air Blast Circuit Breaker Replacement – Bruce B SS
Targeted Start Date: Q2 2017
Targeted In-service Date: Q4 2020
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Bruce B SS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Bruce B SS is a critical network station connecting the Bruce Power Nuclear Generation Station to the 500kV transmission network. The Bruce B SS 500kV switchyard was originally placed in-service in the 1981 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are ten 500kV ABCBs at Bruce B SS that are 37 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Bruce B SS.

This project entails:

- Replacement of ten 500kV ABCBs, associated disconnect switches, and protection and control equipment needed to meet NPCC standards; and
- Removal of twenty sets of free standing transformers along with the entire high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs for projects of similar scope.

Outcome:
To eliminate operational risks associated with end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.0	26.4	70.1
Operations, Maintenance & Administration and Removals	(0.1)	(1.8)	(4.9)
Gross Investment Cost	**0.9**	**24.6**	**65.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.9**	**24.6**	**65.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Air Blast Circuit Breaker Replacement – Cherrywood TS 230 KV
Targeted Start Date: Q4 2018
Targeted In-service Date: Q4 2020
Targeted Outcome: *Operational Effectiveness*

Need:
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Cherrywood TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Cherrywood TS is a critical network station connecting the Ontario Power Generation's ("OPGs") Pickering Nuclear Generating Station as well as a considerable portion of the output of OPG's Darlington Nuclear Generating Station to the 500kV and 230kV transmission network. The facility was originally placed in-service in 1969 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Cherrywood TS.

This project entails:

- Replacement of twelve ABCBs, associated breaker disconnect switches, station AC & DC systems as well as protection and control equipment needed to meet NPCC standards; and
- Removal of twenty-four sets of free standing transformers along with portions of the high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs for projects of similar scope.

Outcome:
To reduce operational risks associated with the operation of end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.5	4.1	65.1
Operations, Maintenance & Administration and Removals	(0.1)	(0.3)	(4.5)
Gross Investment Cost	**1.4**	**3.8**	**60.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**1.4**	**3.8**	**60.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Air Blast Circuit Breaker Replacements - Lennox TS
Targeted Start Date: Q2 2016
Targeted In-Service Date: Q1 2020
Targeted Outcome: *Operational Effectiveness*

Need:
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Lennox TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Lennox TS is a critical network station connecting a considerable portion of Ontario Power Generation's ("OPGs") Darlington Nuclear Generating Station to the 500kV and 230kV transmission network. The facility was originally placed in-service in 1974 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are 14 ABCBs at Lennox TS that are over 40 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Lennox TS.

This project entails:

- Replacement of eight 230kV ABCBs, six 500kV ABCBs, two 230kV oil circuit breakers, associated breaker disconnect switches, transformer and line disconnect switches as well as protection and control equipment needed to meet NPCC standards; and
- Removal of twenty-two sets of free standing transformers along with the entire high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	26.1	20.4	94.4
Operations, Maintenance & Administration and Removals	0.0	(3.5)	(10.7)
Gross Investment Cost	**26.1**	**16.9**	**83.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**26.1**	**16.9**	**83.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Air Blast Circuit Breaker Replacement – Richview TS
Targeted Start Date: Q1 2014
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Richview TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission station. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Richview TS is a critical network station that facilitates bulk power transfers on the 230 kV transmission network and transforms 230kV to 27.6kV for load delivery within the GTA. The facility was originally placed in-service in 1957 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with NPCC reliability standards is required.

There are twenty-four 230kV ABCBs at Richview TS that are 50 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Richview TS.

The project entails:

- Replacement of twenty-four ABCBs, three oil breakers, associated breaker disconnect switches, DC systems as well as protection and control equipment needed to meet NPCC standards; and
- Removal of forty-eight sets of free standing transformers along with the entire high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on detailed cost estimate prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	19.5	14.3	102.3
Operations, Maintenance & Administration and Removals	(2.6)	(0.8)	(6.8)
Gross Investment Cost	**16.9**	**13.5**	**95.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**16.9**	**13.5**	**95.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Beach TS
Targeted Start Date: Q2 2014
Targeted In-service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Beach TS that are in need of replacement due to poor condition, obsolescence, high maintenance costs, asset demographics and non-standard assets that directly impact the operability and system reliability. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the industrial customers within the City of Hamilton.

Investment Summary:
Built in the late 1940's, Beach TS is a network facility located within the industrial core in the City of Hamilton connecting to both the 230 kV and 115 kV transmission networks. Beach TS directly supplies the industrial customer ArcelorMittal Dofasco ("AMD"), local distribution company Horizon Utilities Corporation, and several Hydro One transformer stations within the industrial corridor and downtown core of the City of Hamilton.

The oil analysis results of two of the transformers at Beach TS show signs of insulation degradation indicating there is an increased probability of failure. In addition, these units are leaking oil from the voltage regulation component posing a risk to the environment. The proximity of these transformers to the station administrative buildings has also been identified as a safety concern and must be relocated to ensure sufficient separation.

The project entails:

- Extensive refurbishment and reconfiguration of Beach TS which will result in the replacement of two transformers, seven 230kV oil circuit breakers, one 115 kV oil circuit breaker, associated disconnect switches, and protection, control and telecom equipment;
- Upgrading of oil spill containment facilities to comply with the Ministry of Environment and Climate Change ("MOECC") requirements.

The new power transformers will be reconnected from the 115kV to the 230kV system to improve the reliability of supply to customers and reduce loading on the 115kV network in Hamilton/Niagara area. The upgrade of protection, control and telecom facilities will ensure compliance with the Northeast Power Coordinating Council ("NPCC") requirements.

Alternatives:
Three alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: In-Situ replacement of the assets; or
- Alternative 3: Relocated replacement of the assets.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition, safety concerns, and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. However Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not eliminate safety concerns regarding the proximity of the transformer to administrative buildings and would not allow for the reconnection of the transformers to the 230 kV network to alleviate congestions on the 115 kV system.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, increase capacity on the 115 kV system, maintain system reliability, and ensure compliance with MOECC and NPCC requirements.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	16.7	15.9	77.3
Operations, Maintenance & Administration and Removals	(0.2)	0.0	(0.8)
Gross Investment Cost	**16.5**	**15.9**	**76.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**16.5**	**15.9**	**76.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Centralia TS
Targeted Start Date: Q3 2016
Targeted In-service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Centralia TS that are in need of replacement due to degraded condition that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the early 1950's, Centralia TS is a 64 year old transformer station that consists of a non-standard three transformer configuration, supplying load to Hydro One Distribution customers in the area. The oil analysis results of these transformers shows advanced signs of insulation degradation indicating that there is an increased probability of failure. In addition, two of the units have experienced multiple oil leaks posing a risk to the environment. All of the protection and control facilities have passed their expected service life and are obsolete. A majority of the circuit breakers are also obsolete and are beyond their end of life with operations exceeding manufacturer's design specification.

The project entails:

- Reconfiguration of Centralia TS by replacing and upgrading end of life facilities with new equipment built to current standards including: the 115-27.6 kV transformers, the existing air insulated 27.6kV switchyard (including eight circuit breakers) with a new medium voltage gas-insulated switchgear building installation, the existing protections, control and telecom ("PCT") equipment with a modern PCT solution, and the oil spill containment facilities in compliance with the Ministry and Environment and Climate Change ("MOECC") requirements; and
- Removal of one transformer, one breaker and associated systems that will no longer be required as a result of the reconfiguration to a standardized design.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: “Like-for-Like” replacement of the assets; and
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not address the non-standard design configuration resulting in the need for an additional transformer; which would increase overall project costs as well as long term maintenance commitments.

Basis for Budget Estimate:

The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:

To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	12.5	6.2	20.7
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**12.5**	**6.2**	**20.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**12.5**	**6.2**	**20.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Station Reinvestment - Dryden TS
Targeted Start Date: Q1 2015
Targeted In-Service Date: Q4 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Dryden TS that are in need of replacement due to poor condition, obsolescence and high maintenance costs, which directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the Dryden area; as well as negatively impact transmission capacity and security in Northwestern Ontario.

Investment Summary:
Built in the early 1950's, Dryden TS is a major hub for East-West power flow on the 115kV and 230kV systems in Northwestern Ontario. The transformer station consists of a non-standard three transformer configuration supplying load to Hydro One Distribution customers in the area. All three transformers are currently exhibiting multiple oil leaks. Several of the high voltage oil breakers have also been deemed end of life due to condition and there is a lack of spare part availability.

The project entails:

- Reconfiguration of Dryden TS by replacing and upgrading existing facilities with new equipment built to current standards including: the 115/44kV transformers, five high voltage oil circuit breakers, the disconnect switches, all protection and control systems, and other associated auxiliary components; as well as the oil spill containment facilities will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements; and
- Replacement of three transformers with two standard units; the one transformer will no longer be required as a result of the reconfiguration to a standardized design.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: “Like-for-Like” replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not address the non-standard design configuration resulting in the need for an additional transformer; which would increase overall project costs as well as long term maintenance commitments.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	16.2	0.1	31.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**16.2**	**0.1**	**31.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**16.2**	**0.1**	**31.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Elgin TS
Targeted Start Date: Q3 2015
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Elgin TS that are in need of replacement due to poor condition, obsolescence and high maintenance costs, which directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the late 1960's, Elgin TS is a 48 year old transformer station that supplies load to Horizon Utilities Corporation which serves the downtown core of the City of Hamilton. The oil analysis results of all four transformers at Elgin TS show signs of internal arcing, overheating, and insulation degradation indicating that there is an increased probability of failure. The low voltage switching facilities have also been deemed end of life due to condition, performance, obsolescence and safety concerns over inadequate arc resistance.

The project entails:

- Reconfiguration of Elgin TS by replacing and upgrading existing facilities with new equipment built to current standards including: the 115/13.8kV transformers, the low voltage switching facilities (including thirty-eight low voltage breakers) with a new medium voltage gas-insulated switchgear building installation, protection and control facilities, and other associated ancillary equipment; as well as the oil spill containment facilities will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements; and
- Replacement of four transformers with two standard units; the other two transformers will no longer be required as a result of the reconfiguration to a standardized design.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not address the non-standard design configuration resulting in the need for additional transformers; which would increase overall project costs as well as long term maintenance commitments.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	22.6	17.8	58.2
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**22.6**	**17.8**	**58.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**22.6**	**17.8**	**58.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Station Reinvestment - Espanola TS
Targeted Start Date: Q4 2014
Targeted In-Service Date: Q4 2016
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Espanola TS that are in need of replacement due to degraded condition and asset demographics, which directly impact the operability and reliability of the transformer station and the 115kV circuit (S2S) supplying the local area. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the early 1950's, Espanola TS is a 63 year old transformer station that serves as the load transfer point for the 115kV circuit (S2S) between Algoma TS and Martindale TS and supplies load to Espanola Regional Hydro Distribution and Hydro One Distribution customers around the town of Espanola in Northeastern Ontario. The oil analysis results of one of the transformers at Espanola TS shows signs of insulation system degradation indicating that there is an increased probability of failure in the near term. This unit has also been experiencing recurring oil leaks, and attempts to repair the leaks have not been completely successful. The oil analysis results of the other transformer have identified high PCB content in the bushings of the transformer. The protections for transformers and breakers have also been deemed end of life and are obsolete.

The project entails:

- Complete rebuild of the Espanola TS by replacing existing aged and degraded infrastructure with new equipment built to current standards including: two 115/44kV transformers, three circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components; as well as the oil spill containment facilities will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements; and
- Replacement of the 115kV circuit S2B line protections at Algoma TS and Manitoulin TS, and the disconnect switches at Manitoulin TS.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Alternative 2 is the preferred solution as it minimizes risks associated with the existing infrastructure condition, performance, utilization, obsolescence, and criticality. It also addresses the PCB content within transformers that must be remediated to meet PCB regulations.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	3.0	0.0	24.9
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**3.0**	**0.0**	**24.9**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.0**	**0.0**	**24.9**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Gage TS
Target Start Date: Q1 2017
Targeted In-service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Gage TS that are in need of replacement due to degraded condition and asset demographics that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Gage TS is a transformer station that supplies load to Horizon Utilities Corporation in the city of Hamilton and other major industrial customers including: US Steel, Max Aicher North America, and ArcelorMittal Dofasco. The station was originally placed in-service in 1940 with additional capacity installed in the 1960s. Since Gage TS supplies critical industrial customer loads there have been no major refurbishments at the station since its inception due to the unavailability of outages to perform the work. The oil analysis results on four transformers at Gage TS have repeatedly shown advanced signs of insulation degradation, indicating that there is an increased probability of failure in the near term. In addition, several low voltage circuit breakers are in poor condition, are an obsolete design and spare part availability is limited.

The project entails a partial rebuild and reconfiguration of Gage TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. The customer load at the station has reduced substantially over the years to about a third of the installed capacity. As a result, the station will be reconfigured from the existing three switchyards supplied by six transformers and consolidated to consist of two switchyards supplied by four transformers with increased ratings in order to maintain reliability and supply capability. Equipment to be replaced in this project includes: the 115/13.8kV transformers and associated spill containment systems in compliance with the Ministry of Environment and Climate Change (“MOECC”) requirements, thirteen circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would continue maintaining six transformers and the associated three switchyards; which was not deemed prudent given the reduction in loading.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the consolidation of two switchyards.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.3	13.3	38.0
Operations, Maintenance & Administration and Removals	(0.1)	(0.9)	(2.0)
Gross Investment Cost	**1.2**	**12.4**	**36.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**1.2**	**12.4**	**36.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment – Kenilworth TS
Targeted Start Date: Q3 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:

To address multiple assets at Kenilworth TS that are in need of replacement due to degraded condition and asset demographics that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the major industrial customers located within the City of Hamilton.

Investment Summary:

Built in the early 1950's, Kenilworth TS is a 65 year old transformer station that supplies load to Horizon Utilities Corporation which serves the City of Hamilton. The oil analysis results for one of the transformers at Kenilworth TS has shown advanced signs of insulation degradation indicating there is an increased probability of failure in the near term and is consistently leaking oil. The low voltage metalclad switching facilities have also been deemed end of life due to condition, performance and safety concerns over inadequate arc flash resistance. All of the station protection, control and telecom facilities have reached end of life and are obsolete.

The scope of this project will entail the reconfiguration of Kenilworth TS, replacing existing facilities with new equipment built to current standards. The existing station configuration consists of three switchyards supplied by four transformers. However, one of the metalclad switchyards and two power transformers are presently out of service and are no longer required due to significant reduction in loading in the area. Therefore the station will be reconfigured and consolidated to consist of two switchyards supplied by two transformers with increased ratings in order to maintain reliability and supply capability. Equipment to be replaced within this project includes: one 115/13.8kV power transformer, fifteen low voltage breakers, all associated protection, control and telecom facilities, and other associated ancillary equipment; as well as the oil spill containment will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo).
- Alternative 2: “Like-for-Like” replacement of the assets.
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would continue maintaining four transformers and the associated switchyards; which was not deemed prudent given the reduction in loading.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	6.0	12.0	20.0
Operations, Maintenance & Administration and Removals	(0.4)	(0.8)	(1.4)
Gross Investment Cost	**5.6**	**11.2**	**18.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.6**	**11.2**	**18.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Station Reinvestment – Nelson TS
Start Date: Q2 2016
Targeted In-service Date: Q1 2019
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address multiple assets at Nelson TS that are in need of replacement due to degraded condition and asset demographics that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration, declining reliability to the customers in the area, and a failure to meet a customer request to accommodate a voltage conversion.

Investment Summary:
Nelson TS is a transformer station that supplies load to London Hydro in the City of London via two 13.8kV switchyards. The first switchyard was built in 1948, and the second switchyard was added in 1970s. The oil analysis results on two of the existing four transformers have repeatedly shown signs of insulation degradation indicating that there is an increased probability of failure in the near term. The low voltage switching facilities are also deemed end of life due to a combination of condition, manufacturer obsolescence and the unavailability of spare parts. Furthermore, the sole connected customer to Nelson TS, London Hydro, has requested a secondary voltage conversion from a 13.8 kV supply to a 27.6 kV supply.

The project entails the replacement and reconfiguration of Nelson TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. The existing station configuration consists of two switchyards with four transformers. At the request of London Hydro to increase the secondary voltage from 13.8 kV to 27.6 kV, the station will be reconfigured and consolidated to consist of one new 27.6kV switchyard with medium voltage gas insulated switchgear. A capital contribution will be made from the customer for the incremental cost of this conversion. Equipment to be replaced includes four power transformers, thirty low voltage breakers, associated protection, control and telecom facilities with a modern solution, and other associated auxiliary equipment; as well as the oil spill containment facilities will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements. Four transformers will be replaced with two standard units, the other two transformers will no longer be required as a result of the reconfiguration to a single switchyard design.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not address the customer's request for secondary voltage conversion.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs.

Costs:
The capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.9	20.2	38.8
Operations, Maintenance & Administration and Removals	0.0	0.0	(5.8)
Gross Investment Cost	**10.9**	**20.2**	**33.0**
Capital Contribution	(8.8)	0.0	(10.5)
Net Investment Cost	**2.1**	**20.2**	**22.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Palmerston TS
Targeted Start Date: Q4 2016
Targeted In-service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Palmerston TS that are in need of replacement due to degraded condition and asset demographics that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the early 1950's, Palmerston TS is a 64 year old transformer station that supplies load to Hydro One Distribution customers in the town of Palmerston. Two of the three transformers are exhibiting recurring oil leaks, and the third unit has developed leaks within the voltage regulation component. Spare part availability for all three transformers is limited and no manufacturer support is available. All of the protection and control facilities have passed their expected service life and are obsolete. There are also several circuit breakers that are obsolete and are beyond their end of life with operations exceeding the manufacturer's design specification.

The project entails the complete rebuild and reconfiguration of Palmerston TS by replacing and upgrading the existing facilities with new equipment built to current standards including: the 115/44kV transformers, the existing air insulated switchyard, the control and telecom equipment with a modern solution, and other ancillary station service equipment. In addition, the oil spill containment facilities will be upgraded to comply with requirements of the Ministry of Environment and Climate Change ("MOECC"). Three transformers will be replaced with two standard units, the one transformer and associated breaker will no longer be required as a result of the reconfiguration to a standardized design.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all of the needs of the station. Alternative 2 would not address the non-standard design configuration resulting in the need for an additional transformer; which would increase overall project costs as well as long term maintenance commitments.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	9.5	12.5	27.0
Operations, Maintenance & Administration and Removals	(0.7)	(0.9)	(1.9)
Gross Investment Cost	**8.8**	**11.6**	**25.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.8**	**11.6**	**25.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Wanstead TS
Targeted Start Date: Q3 2016
Targeted In-service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness***,** *Customer Focus*

Need:
To address multiple assets at Wanstead TS that are in need of replacement due to degraded condition and asset demographics that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the late 1940's, Wanstead TS is a 67 year old transformer station that supplies Hydro One Distribution and the embedded local distribution company, Bluewater Power, in the County of Plympton in southwestern Ontario. The oil analysis results of all three existing transformers have repeatedly shown advanced signs of insulation degradation indicating that there is an increased probability of failure in the near term. In addition, all three transformers have developed oil leaks and pose an environmental risk if not mitigated. Several low voltage circuit breakers are beyond their end of life with unavailability of spare parts, and are experiencing poor performance with operations exceeding the manufacturer's design specification. Furthermore, the customers, Hydro One Distribution and Bluewater Power, have requested the station be converted from the existing 115 kV single supply connection to a dual supply 230 kV connection to improve reliability and delivery point performance.

The project entails a complete rebuild and reconfiguration of Wanstead TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. The station will be rebuilt in a greenfield location on existing Hydro One property. The existing air insulated switchgear will be replaced with new medium voltage gas insulated switchgear and will be reconfigured from a non-standard three transformer design to a standard two transformer design supplied from new connections to the 230 kV transmission system via circuits N21W and N22W. Equipment to be replaced includes: the power transformers, seven low voltage circuit breakers, associated protection, control and telecom facilities, and other associated auxiliary components. Oil spill containment facilities will also be upgraded to comply with Ministry of Environment and Climate Change ("MOECC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not address the reliability and performance concerns associated with a single circuit supply from the 115 kV transmission system.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs.

Costs:
The capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	13.7	14.3	31.8
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**13.7**	**14.3**	**31.8**
Capital Contribution	(2.0)	(1.3)	(3.3)
Net Investment Cost	**11.7**	**13.0**	**28.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Alexander SS
Targeted Start Date: Q4 2016
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Alexander SS that are in need of replacement due to poor condition; obsolescence, declining performance and high maintenance costs. These assets directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk that equipment continues to deteriorate, contributing to declining reliability to the customers in the area and negatively impact transmission capacity and security in Northwestern Ontario.

Investment Summary:
Alexander SS is a switching station that serves as the connection point for Ontario Power Generation's ("OPG's") Alexander and Cameron Falls generating stations in Northwestern Ontario. Several of the high voltage circuit breakers at Alexander SS are deemed end of life due to poor condition, performance and known operating issues. The associated protection and control facilities are also obsolete and deemed end of life.

The project entails the refurbishment of the Alexander SS station; replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced as part of this project includes: ten high voltage oil circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	15.5	9.5	25.8
Operations, Maintenance & Administration and Removals	(1.1)	(0.7)	(1.8)
Gross Investment Cost	**14.4**	**8.8**	**24.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**14.4**	**8.8**	**24.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement – Allanburg TS
Start Date: Q3 2015
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Allanburg TS that are need of replacement due to poor condition, obsolescence, high maintenance costs, asset demographics and non-standard design, which directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the early 1950's, Allanburg TS is a 230/115kV transformer station that serves as a connection point for the 230 kV and 115kV transmission system and also supplies load to four local distribution companies and eighteen direct industrial customers in the Niagara region. One of the critical 230/115 kV autotransformers at Allanburg TS has been identified as a capacity limiting component for power flow in the Niagara area causing system constraints. Other ancillary station equipment including protection, control and telecom facilities and station service infrastructure has been identified as end of life through diagnostic testing and visual inspections.

The project entails the replacement of assets at Allanburg TS with new equipment built to current standards, including: one underrated and capacity limiting autotransformer, associated disconnect switches, transformer surge protection, station drainage systems, protection, control and telecom facilities, and other ancillary equipment. Oil spill containment facilities will be upgraded to comply Ministry of Environment and Climate Change ("MOECC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, would result in increased maintenance expenses, and would not resolve capacity constraints.

Basis for Budget Estimate:
The project cost is based on detailed cost estimated prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, alleviate capacity constraints, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.0	1.2	33.5
Operations, Maintenance & Administration and Removals	(0.3)	(0.2)	(0.7)
Gross Investment Cost	**4.7**	**1.0**	**32.8**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.7**	**1.0**	**32.8**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Aylmer TS
Targeted Start Date: Q4 2015
Targeted In-Service Date: Q2 2017
Targeted Outcome: *Operational Effectiveness, Customer Focus*

Need:
To address multiple assets at Aylmer TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in 1950, Aylmer TS is a 66 years old transformer station, with much of the original equipment still in service. The equipment supplies load to Hydro One Distribution and local distribution company Erie Thames Powerline Corporation in the southeast of London. The oil analysis results of the transformers show advanced signs of insulation degradation, indicating that there is an increased probability of failure. The transformers have also developed oil leaks and pose an environmental risk if not mitigated. These transformers are a non-standard and obsolete design. The low voltage switchyard and associated facilities are also non-standard and obsolete. Visual inspection and diagnostic testing also indicate that they are at the end of life. All of the protection and control facilities have passed their expected service life and are obsolete. Distribution customers served by Aylmer TS have requested new feeder positions to be added to expand supply to serve additional customers.

The project entails the refurbishment of Aylmer TS by replacing and upgrading end of life facilities with new standard equipment built to current standards including: two transformers and associated oil spill containment facilities, the 27.6kV switchyard with a new medium voltage gas insulated switchgear consisting of eight low voltage breakers, the protection, control and telecom (“PCT”) equipment with a new modern PCT solution design, and other ancillary station equipment to improve supply reliability. Additional feeder positions will be constructed at the request of connected customers.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on detailed cost estimated prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.0	0.0	23.9
Operations, Maintenance & Administration and Removals	(0.5)	0.0	(0.5)
Gross Investment Cost	**3.5**	**0.0**	**23.4**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.5**	**0.0**	**23.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Barrett Chute SS
Targeted Start Date: Q3 2016
Targeted In-Service Date: Q2 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Barrett Chute SS that are in need of replacement due to poor condition, obsolescence, declining performance and high maintenance costs. This equipment directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area. It would also negatively impact transmission capacity and security in Eastern Ontario.

Investment Summary:
Built in the late 1960's, Barrett Chute SS is a switching station connecting 176MW of generation from the Ontario Power Generation's ("OPG's") Barrett Chute generating station to the 115kV transmission system. Several of the high voltage circuit breakers at Barrett Chute SS are deemed end of life due to poor condition, performance and known operating issues. The associated protection and control facilities are also obsolete and deemed end of life.

The project entails the rebuild of the Barrett Chute SS station; replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: six oil circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components. The protection and control systems, and other associated auxiliary components currently located in OPG facilities will be relocated to Hydro One Transmission facilities as part of this project. The relocation of Hydro One Transmission assets from OPG facilities will result in a clearly defined demarcation point for asset ownership and operating authority.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.0	4.2	18.7
Operations, Maintenance & Administration and Removals	(0.7)	(0.3)	(1.0)
Gross Investment Cost	**9.3**	**3.9**	**17.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**9.3**	**3.9**	**17.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Birch TS
Targeted Start Date: Q4 2016
Targeted In-Service Date: Q3 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Birch TS that are in need of replacement due to poor condition, obsolescence, declining performance and high maintenance costs. The equipment directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area. It would also negatively impact transmission capacity and security in Northwestern Ontario.

Investment Summary:
Built in 1955, Birch TS is a major hub for East-West power flow on the transmission system in Northwestern Ontario and also supplies load to Thunder Bay Hydro. Several of the high voltage circuit breakers at Birch TS are deemed end of life due to poor condition, performance and known operating issues. The associated protection and control facilities are also obsolete and deemed end of life.

The project entails replacement of assets in both the high voltage and low voltage switchyards with new equipment built to current standards. In the high voltage switchyard the equipment to be replaced includes: seven oil circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components. In the low voltage switchyard the equipment to be replaced includes: the oil spill containment facilities to comply with Ministry of Environment and Climate Change ("MOECC") requirements, capacitor banks, disconnects switches, protection and control systems, and other associated auxiliary components.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	13.0	14.9	32.7
Operations, Maintenance & Administration and Removals	(0.9)	(1.1)	(2.2)
Gross Investment Cost	**12.1**	**13.8**	**30.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**12.1**	**13.8**	**30.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Bronte TS
Targeted Start Date: Q4 2016
Targeted In-Service Date: Q3 2019
Targeted Outcome: *Operational Effectiveness*

Need:

To address multiple assets at Bronte TS that are in need of replacement due to obsolescence, non-standard assets, and degraded condition that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:

Built in the early 1960's, Bronte TS is a 53 year old transformer station that supplies load to local distribution companies, Oakville Hydro and Burlington Hydro Inc., via two low voltage switchyards. The oil analysis results for two of the transformers at Bronte TS show signs of internal overheating, indicating that there is an increased probability of failure. These units also have significant oil leaks that pose an environmental risk if not mitigated. In addition, the voltage regulation equipment installed on the unit has been deemed end of life by the manufacturer and can longer be supported or maintained. The low voltage switching assets are also in degraded condition, as identified through visual inspection and diagnostic testing.

The project entails the replacement of assets at Bronte TS with new equipment built to current standards including: two power transformers, oil spill containment facilities to comply with the Ministry of the Environment and Climate Change ("MOECC") requirements, all low voltage air insulated switchgear and structures, station service transformers, and all associated protection, control and telecom facilities. The replacement of these assets will be accomplished through expansion of the existing station footprint into the adjacent Crown land. This approach will greatly reduce outage durations and supply constraints which would otherwise negatively impact the local distribution companies and its connected customers.

Alternatives:
Three alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: In-Situ replacement of the assets; or
- Alternative 3: Relocated replacement of the assets.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative, as Alternative 2 would impose staging risks associated with maintaining supply to the local distribution company in addition to space limitations posed by the station property.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:

To eliminate operational risks associated with operating end of life equipment, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.0	18.4	35.5
Operations, Maintenance & Administration and Removals	(0.3)	(1.3)	(2.4)
Gross Investment Cost	**3.7**	**17.1**	**33.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.7**	**17.1**	**33.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Bridgman TS
Targeted Start Date: Q4 2018
Targeted In-Service Date: Q2 2022
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address multiple assets at Bridgman TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Built in the early 1950's, Bridgman TS is a transformer station that supplies load to Toronto Hydro ("THESL") in the city of Toronto. The three transformers at the station range in age from 58 to 60 years old at Bridgman TS. Oil analysis results of these transformers show signs of overheating and insulation degradation indicating that there is an increased probability of failure. Two of the units are also experiencing multiple oil leaks that pose a risk to the environment if not mitigated. There are also two metalclad switchgear lineups with breakers that are 53 to 55 years old that have been identified as a safety concern due to the lack of arc flash protection. These assets require additional maintenance due to the design of the breakers and use of air pressure vessels. THESL has requested that the capacity of the three transformers be increased in order to meet future load growth in the area.

This project entails the partial refurbishment of Bridgman TS by replacing existing assets and infrastructure that are deteriorated in condition with new equipment built to current standards. Equipment to be replaced include three 115kV power transformers and associated oil spill containment systems to comply with Ministry of the Environment and Climate Change ("MOECC") requirements, six metalclad breakers, surge arresters, neutral grounding reactors, and disconnect switches. In addition, infrastructure such as drainage, steel support structures, foundations, cable tunnels and trenches, high and low voltage buswork will need to be replaced or upgraded due to deteriorating condition and to facilitate replacement of the major assets.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks and safety issues associated with operating end of life equipment, maintain system reliability, and increase available capacity to supply THESL customers in the area.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	0.2	3.6	42.8
Operations, Maintenance & Administration and Removals	0.0	(0.3)	(2.9)
Gross Investment Cost	**0.2**	**3.3**	**39.9**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.2**	**3.3**	**39.9**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Buchanan TS
Targeted Start Date: Q2 2015
Targeted In-Service Date: Q4 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Buchanan TS that are in need of replacement due to poor condition, obsolescence, declining performance and high maintenance costs. These assets directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

Investment Summary:
Buchanan TS is a critical network station that connects high voltage circuits serving the south western corridor of Ontario between Kitchener and Chatham. It also has a low voltage switchyard that supplies load to several customers including: Erie Thames Power Lines Corporation, London Hydro Inc., and large retail customers such as Lafarge Woodstock in the London area. The two high voltage capacitor banks at Buchanan TS are a non-standard and obsolete design that are deemed end of life and can no longer be prudently maintained. The associated capacitor bank breakers are also deemed end of life, with operations exceeding manufacturer's design specifications. Several of the protection and control assets are also obsolete and are deemed at end of life with unreliable performance and are non-compliant with the Northeast Power Coordinating Council ("NPCC") requirements. A significant number of security incidents have occurred over recent years that have prompted a review of the physical security measures in place at Buchanan TS.

The project entails the replacement of assets at Buchanan TS with new equipment built to current standards including: the two non-standard capacitor banks and associated breakers, disconnect switches, instrument transformers, and protection and control systems. There will also be eighteen protection systems added to meet NPCC requirements and additional security infrastructure will be installed at the site to minimize and prevent future security incidents.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

To alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or ensure compliance with NPCC requirements, and would result in increased maintenance expenses.

Basis for Budget Estimate:

The project cost is based on detailed cost estimated prepared by Hydro One.

Outcome:

To maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.2	0.0	29.8
Operations, Maintenance & Administration and Removals	0.0	0.0	(0.1)
Gross Investment Cost	**4.2**	**0.0**	**29.7**
Capital Contribution	0.0	0.0	0.0
Net Capital Investment Cost	**4.2**	**0.0**	**29.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Cecil TS
Targeted Start Date: Q1 2017
Targeted In-Service Date: Q4 2017
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
Multiple assets at the assets at the Cecil TS need to be addressed. These assets are in need of replacement due to deteriorating condition, declining performance, and obsolescence. These assets directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in an increased risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Built in 1970, Cecil TS is a transformer station that supplies load to Toronto Hydro ("THESL") in the downtown core of the city of Toronto. The oil analysis results of the transformers show signs of overheating which leads to degradation of the internal transformer insulation indicating that there is an increased probability for failure. There is also protection, control, and telecom equipment that are at end of life and do not meet current standards. THESL has requested that the capacity of the transformers be increased in order to meet future load growth in the area.

The project entails the replacement of assets at Cecil TS with new equipment built to current standards, including: one 115kV power transformer, the DC station service, and select protection, control, and telecom equipment.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment while maintain system reliability.

Costs:
The capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.3	0.0	12.9
Operations, Maintenance & Administration and Removals	(0.7)	0.0	(0.7)
Gross Investment Cost	**9.6**	**0.0**	**12.2**
Capital Contribution	(0.2)	0.0	(0.2)
Net Investment Cost	**9.4**	**0.0**	**12.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement – Chenaux TS
Targeted Start Date: Q4 2014
Targeted In-Service Date: Q4 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Chenaux TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transformer station. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in 1950, Chenaux TS is a major network station in the Eastern region that connects 144MW of generation from Chenaux GS to the 230kV transmission system. The two transformers at Chenaux TS have developed oil leaks. Due to the proximity to nearby water and the condition of existing spill containment, it poses significant environmental risks. Due to the age of the units, at 68 years and 65 years old respectively, oil leak mitigation would not be prudent at this time due to uncertainty in part availability and risk associated with damaging other seals or components during the repair process. The associated protection and control facilities are also end of life and have been deemed obsolete.

The project entails the partial rebuild of Chenaux TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: two transformers, associated spill containment systems to comply with Ministry of Environment and Climate Change (“MOECC”) requirements, two circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or the potential impact to the environment, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, mitigate the potential environmental risk associated with the current infrastructure, and reduce long term maintenance costs.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	7.8	2.1	20.1
Operations, Maintenance & Administration and Removals	(0.3)	0.0	(0.6)
Gross Investment Cost	**7.5**	**2.1**	**19.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**7.5**	**2.1**	**19.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Crawford TS
Start Date: Q1 2017
Targeted In-Service Date: Q4 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Crawford TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the late 1940's, Crawford TS is a 67 year old transformer station that supplies EnWin Utilities in the Windsor area. One of the transformers at Crawford has been deemed end of life due to continuous oil leaks from critical voltage regulation equipment. Due to the age of the unit, at 56 years old, repairing the leak is uncertain due to part availability and the risk associated with damaging other seals or components during the process. The station also contains end of life ancillary equipment located below grade which presents an operational risk in the event of flooding. In addition, the control equipment is obsolete and is no longer supported by the manufacturer.

The project entails the replacement of assets at Crawford with new equipment built to current standards including: the single power transformer, associated spill containment facilities and ancillary equipment, and control equipment.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.2	0.0	8.4
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**4.2**	**0.0**	**8.4**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.2**	**0.0**	**8.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - DeCew Falls SS
Start Date: Q2 2016
Targeted In-Service Date: Q3 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at DeCew Falls SS that are in need of replacement due to poor condition, obsolescence, high maintenance costs and asset demographics. These assets directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in 1955, DeCew Falls SS is located within the city of St. Catharines and is the connection point for Ontario Power Generation's ("OPG's") DeCew Falls generating station. It is also a major supply point for the 115kV transmission system in the Niagara region, serving the cities of Niagara Falls, St. Catharines, Niagara-on-the-Lake, Thorold, Welland and the surrounding area. The failure of a high voltage oil circuit breaker at DeCew Falls SS in 2012 prompted a review of the condition of the remaining five oil circuit breakers. All of the remaining circuit breakers have been deemed end of life due to condition, performance, and supportability and spare parts obsolescence. All the protection, control and telecom equipment has been deemed end of life, as it is obsolete and is no longer supported by the manufacturer. The station currently relies on a single ancillary station service supply from OPG's DeCew Falls Generating Station and does not meet current reliability standards.

The project entails the replacement of assets at DeCew Falls SS with new equipment built to current standards, including: five 115kV oil circuit breakers, associated disconnect switches, ancillary station service facilities, line disconnect switches and all station protection, control and telecom equipment. An additional station service supply will be installed to meet reliability requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and potential for interruptions to the DeCew Falls generating station and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment and maintain the reliability of the connection point for the DeCew Falls generating station and the 115 kV transmission network in the Niagara area.

Costs:

($ Million)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.3	0.0	13.0
Operations, Maintenance & Administration and Removals	(0.4)	0.0	(0.4)
Gross Investment Cost	**4.9**	**0.0**	**12.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.9**	**0.0**	**12.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Dufferin TS
Targeted Start Date: Q4 2016
Targeted In-Service Date: Q2 2019
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address multiple assets at Dufferin TS that are in need of replacement due to degraded condition, which directly impacts the operability and reliability of the transmission station. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to Toronto Hydro ("THESL") customers in the area.

Investment Summary:
Build in the mid 1960's Dufferin TS is a 52 year old transformer station that supplies load to THESL customers in the downtown Toronto area via two switchyards. Oil analysis results of three transformers at the Dufferin TS have shown evidence of overheating which leads to degradation of the internal transformer insulation, indicating that there is a higher probability of failure. All three units are leaking oil, while two of the units have obsolete tap-changers components which require increased maintenance. The associated protection and control facilities are also obsolete and deemed end of life. THESL has requested that the capacity of the three transformers be increased in order to meet future load growth in the area.

The project entails the replacement of assets at Dufferin TS that are deteriorating condition with new equipment built to current standards, including: three 115kV power transformers, surge arresters, neutral grounding reactors, line disconnect switches, and protection and control systems. In addition, supporting infrastructure such as drainage, wall structures, foundations, and high and low voltage bus work will need to be adjusted to facilitate replacement of the major assets.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life assets, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	7.0	8.0	23.2
Operations, Maintenance & Administration and Removals	(0.5)	(0.6)	(1.5)
Gross Investment Cost	**6.5**	**7.4**	**21.7**
Capital Contribution	0.0	0.0	0.0
Net Capital Investment Cost	**6.5**	**7.4**	**21.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Ear Falls TS
Targeted Start Date: Q4 2014
Targeted In-Service Date: Q3 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Ear Falls TS that are in need of replacement due to poor condition, obsolescence, declining performance and high maintenance costs. These assets directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the mid 1950's, Ear Falls TS is a 60 year old transformer station that provides a radial connection point to several Ontario Power Generation ("OPG") generating stations, as well as supplies load to several Hydro One Distribution stations and large customers in Northwestern Ontario. The two transformers at Ear Falls TS have developed oil leaks and, due to the proximity to nearby water and the condition of existing spill containment, pose significant environmental risks. Due to the age of the units, at 49 years and 67 years old respectively, oil leak mitigation would not be prudent at this time due to uncertainty of spare part availability and risk associated with damaging other seals or components during the repair process. Associated protection and control facilities are end of life and have been deemed obsolete.

The project entails the rebuild of the Ear Falls TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: two transformers, four oil circuit breakers, disconnect switches, protection and control systems, other associated auxiliary components, and the oil spill containment facilities will be upgraded to comply with Ministry of Environment and Climate Change ("MOECC") requirements.

The two existing 115/44 kV transformers will be consolidated and replaced with a single 115/12.5 kV unit, eliminating the need for a distribution class 44/14.4 kV step down transformer in Ear Fall DS, located adjacent to Ear Falls TS.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, potential environmental risk, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, mitigate environmental risks associated with current infrastructure, and reduce long term maintenance costs.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	11.0	0.0	18.7
Operations, Maintenance & Administration and Removals	(0.1)	0.0	(0.4)
Gross Investment Cost	**10.9**	**0.0**	**18.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**10.9**	**0.0**	**18.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement – Frontenac TS
Targeted Start Date: Q1 2016
Targeted In-Service Date: Q2 2018
Targeted Outcome: Operational Effectiveness

Need:
To address multiple assets at Frontenac TS that are in need of replacement due to degraded condition, obsolescence and high maintenance costs that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Built in the late 1930's, Frontenac TS is 78 year old transformer station that supplies load to Kingston Hydro, Hydro One Distribution, a major industrial customer station (Novelis), and is also a connection point for solar and biomass generators in the Greater Kingston area. Several of the high voltage circuit breakers and associated protection and control systems at Frontenac TS have been deemed end of life due to condition, spare part availability, and obsolescence.

The project entails the reconfiguration of the 115kV switchyard at Frontenac TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: four 115kV oil circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components. There will also be one circuit breaker removed that will no longer be required as a result of the reconfiguration of the switchyard.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate the risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.2	1.6	10.3
Operations, Maintenance & Administration and Removals	(0.4)	(0.1)	(0.8)
Gross Investment Cost	**3.8**	**1.5**	**9.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.8**	**1.5**	**9.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Hanmer TS
Targeted Start Date: Q2 2015
Targeted In-Service Date: Q3 2019
Targeted Outcome: *Operational Effectiveness*

Need:

To address multiple assets at Hanmer TS that are in need of replacement due to poor condition, asset demographics, compliance requirements, and safety concerns that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area. It would also negatively impact transmission capacity and security between Northern and Southern Ontario.

Investment Summary:

Built in the mid-1960s, Hanmer TS is a critical network station between Northeastern generation facilities and the majority of load customers located in Southern Ontario. Analysis of the critical 500 kV reactors has identified oil leaks, and significant degradation and corrosion of control box components. There are no spill containment facilities presently installed for these units, which poses a significant environmental risk.

The project entails the replacement of existing aged and degraded infrastructure at Hanmer TS with new equipment built to current standards. Equipment to be replaced includes: two high voltage reactors and associated spill containment systems, eight high voltage circuit breakers, free standing instrument transformers, disconnect switches, protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or the potential environmental risk, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on detailed cost estimated prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and ensure full compliance with NPCC regulations.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	24.5	11.0	63.5
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**24.5**	**11.0**	**63.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**24.5**	**11.0**	**63.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Hawthorne TS
Targeted Start Date: Q3 2015
Targeted In-service Date: Q3 2019
Targeted Outcome: *Operational Effectiveness, Customer Focus*

Need:
To address multiple assets at Hawthorne TS that are in need of replacement due to poor condition, obsolescence and high maintenance costs that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the Greater Ottawa area. It would also negatively impact transmission capacity and security in Eastern Ontario.

Investment Summary:
Built in 1960, Hawthorne TS is a critical network station and a major hub for East-West power flow in Eastern Ontario. The station is also a major supply point for the Greater Ottawa region and supplies load to Hydro Ottawa and Hydro One Distribution. The oil analysis results for the transformers show signs of internal arcing indicating that there is an increased probability of failure in the near term. All associated protection and control facilities are obsolete and have been identified as end of life. Hydro Ottawa has requested that the capacity of the transformers be increased in order to meet Hydro Ottawa projected load growth.

The project entails the replacement of assets at Hawthorne TS with new equipment built to current standards including: two transformers, disconnect switches, three circuit breakers, all protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or the customer's request for increased capacity, and would result in increased maintenance expenses.

Basis for Budget Estimate:

The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs for projects of similar scope.

Outcome:

To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and accommodate the customer request to upgrade station capacity.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.6	4.3	29.1
Operations, Maintenance & Administration and Removals	0.0	0.0	(2.1)
Gross Investment Cost	**1.6**	**4.3**	**27.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**1.6**	**4.3**	**27.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Horning TS
Targeted Start Date: Q3 2016
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:

To address multiple assets at Horning TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers.

Investment Summary:

Build in the late 1960s, Horning TS is a 49 year old transformer station that supplies load to Horizon Utilities Corporation in the downtown core within the City of Hamilton, via two switchyards. Recent failures to low voltage switchgear have impacted supply to customers in the Hamilton area. These low voltage switching facilities have been deemed end of life and pose a safety risk due to inadequate arc flash protection. Both transformers at Horning TS are 49 years old and deemed end of life as result of recurring oil leaks and cooling issues.

The project entails the replacement assets at Horning TS with new equipment built to current standards including: two power transformers and new oil spill containment facilities that comply with Ministry of Environment and Climate Change ("MOECC") requirements, the low voltage switchgear with new medium voltage gas insulated switchgear consisting of twenty-two breakers, all associated protection, control and telecom facilities, and other critical ancillary station equipment. The transformers will be relocated to minimize customer outages and facilitate construction.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	14.3	14.9	37.4
Operations, Maintenance & Administration and Removals	0.0	0.0	(0.8)
Gross Investment Cost	**14.3**	**14.9**	**36.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**14.3**	**14.9**	**36.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Leaside TS BULK
Targeted Start Date: Q2 2015
Targeted In-service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets in the Leaside TS 230kV and 115kV switchyards that are in need of replacement due to poor condition, obsolescence and declining performance that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration, declining reliability to customers in the area, and non-compliance with industry standards.

Investment Summary:
Built in the mid 1950's, Leaside TS is a critical network station that provides 230kV and 115kV switching, transformation of 230kV into 115kV and supplies load to Toronto Hydro ("THESL") in the city of Toronto. The protection systems at Leaside TS are obsolete and not compliant with the Northeast Power Coordinating Council ("NPCC") reliability requirements. There are also nine transformers located at Leaside TS which require oil spill containment upgrades as per direction from the Ministry of Environment and Climate Change ("MOECC").

The project entails the replacement of assets at the Leaside TS 115kV and 230kV switchyard with new equipment built to current standards. Equipment to be replaced includes: sixty-eight protection systems, disconnect switches, and other ancillary equipment. It also includes all nine of the oil spill containment facilities will be upgraded to comply with MOECC requirements. In addition, select supporting infrastructure such as control cabling and cable trenches, road improvements, and wildlife controls will need to be replaced due to deteriorating condition or changed to facilitate replacement of the major assets.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or the requirements of the environmental and reliability standards.

Basis for Budget Estimate:

The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:

To eliminate operational risks associated with operating end of life equipment, and ensure compliance with NPCC and MOECC standards.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	6.0	7.7	33.6
Operations, Maintenance & Administration and Removals	(0.1)	(2.1)	(2.5)
Gross Investment Cost	**5.9**	**5.6**	**31.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.9**	**5.6**	**31.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Leaside TS 27.6kV
Targeted Start Date: Q4 2016
Targeted In-service Date: Q3 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets in the Leaside TS 27.6kV switchyard that are in need of replacement due to poor condition, obsolescence and declining performance that directly impact the operability and reliability of the transmission station. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability customers in the area.

Investment Summary:
Built in the mid 1950's, Leaside TS is a critical network station that provides 230kV and 115kV switching, transformation of 230kV into 115kV and supplies load to Toronto Hydro ("THESL") in the city of Toronto. Most of the 27.6kV switchyard breakers at Leaside TS are 59 years old and are showing signs of degrading performance and deteriorating condition. The breakers and associated switches are mounted in a structure of the same vintage. The structure design has reduced clearance which has contributed to a large number of animal contact outages. This obsolete structure design also limits the ability to perform maintenance without having large outage zones due to safety concerns. The protection and control systems are also beyond their expected service life and are obsolete.

The project entails the complete replacement of the Leaside TS 27.6kV switchyard with new equipment built to current standards. Equipment to be replaced includes: the existing 27.6kV switchyard with a new medium voltage gas insulated switchgear, disconnect switches, protection and control systems, station service equipment and other associated auxiliary components. In addition, infrastructure such as steel support structures, foundations, drainage sections, trenching, control cabling, low voltage buswork and power cabling will need to be replaced due to deteriorating condition and to facilitate replacement of the major assets. The replacement of the Leaside 27.6kV switchyard will also include the replacement of the 27.6kV wholesale revenue metering equipment which will be fully recoverable.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
The two alternatives considered were:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	6.8	7.0	22.5
Operations, Maintenance & Administration and Removals	(0.5)	(0.5)	(1.4)
Gross Investment Cost	**6.3**	**6.5**	**21.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**6.3**	**6.5**	**21.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Main TS
Targeted Start Date: Q2 2017
Targeted In-Service Date: Q2 2019
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address multiple assets at Main TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Main TS is a transformer station that supplies load to Toronto Hydro ("THESL") customers located in the Greater Toronto Area, via THESL owned switchgear. There are two transformers at the station. One of the units is 48 years old and oil analysis results show the transformer overheating, leading to the degradation of the internal transformer insulation and indicating that there is an increased probability of failure. The transformer is also experiencing oil leaks posing risk to the environment. THESL has requested that the capacity of the two transformers be increased in order to meet future load growth in the area.

The project entails the replacement of assets and infrastructure that are deteriorating in condition with new equipment built to current standards. Equipment to be replaced includes: two 115kV transformers, installation of capacitive voltage transformers and other ancillary equipment. In addition, the oil spill containment equipment will be upgraded to comply with Ministry of Environment and Climate Change ("MOECC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life assets, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.8	9.0	26.6
Operations, Maintenance & Administration and Removals	(0.4)	(0.6)	(1.8)
Gross Investment Cost	**5.4**	**8.4**	**24.8**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.4**	**8.4**	**24.8**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Manby TS
Targeted Start Date: Q3 2015
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Manby TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Built in the mid 1940's, Manby TS is critical network station that provides 230 kV and 115kV switching, transformation of 230kV into 115kV and supplies load to Toronto Hydro ("THESL") within the Greater Toronto Area. The protection and control systems at Manby TS are obsolete Programmable Auxiliary Logic Controller ("PALC") relays installed in late 1980's. These relays are at end of life and have been experiencing extremely high failure rates. The SF6 circuit breakers presently installed for capacitor bank switching have experienced a significant number of switching failures and have been identified to contain a design flaw that deem them unsuitable for capacitor bank switching applications.

The project entails the replacement of assets at Manby TS with new equipment built to current standards. Equipment to be replaced includes: two capacitor breakers, disconnect switches, the AC and DC station service and associated transfer schemes, protection and control systems, and other associated auxiliary components. Due to the criticality of the station, the new protection and control systems will need to meet Northeast Power Coordinating Council ("NPCC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or the requirements of the reliability standards.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One utilizing historical costs of project of similar scope.

Outcome:
To eliminate operational risks associated with end of life equipment, maintain system reliability, and ensure compliance with NPCC standards.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.4	1.8	10.2
Operations, Maintenance & Administration and Removals	(1.4)	0.0	(1.4)
Gross Investment Cost	**3.1**	**1.8**	**8.8**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.1**	**1.8**	**8.8**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Martindale TS
Targeted Start Date: Q3 2016
Targeted In-Service Date: Q4 2020
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Martindale TS that are in need of replacement due to poor condition, obsolescence and high maintenance costs that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the Greater Sudbury area. It would also negatively impact transmission capacity and security in Northeastern Ontario.

Investment Summary:
Built in the mid 1930's, Martindale TS is a critical network station that is a major hub for East-West power flow in Northeastern Ontario and supplies load to Sudbury Hydro and Hydro One Distribution in the Sudbury area. Oil analysis results indicate that one of the transformers at Martindale shows advanced signs of insulation degradation indicating there is an increased probability of failure. The equipment on the companion transformer has been identified as capacity limiting for the expected load and noise levels are a concern.

The project entails the replacement of assets at Martindale TS with new equipment built to current standards. Equipment to be replaced includes: two transformers and the associated spill containment facilities to comply with Ministry of Environment and Climate Change "(MOECC") requirements, five circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components. The project also includes the replacement of the low voltage switchyard which includes eleven circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or the requirements of the environmental and reliability standards, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One utilizing historical costs of project of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and ensure compliance with MOECC and NPCC requirements.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	20.0	20.0	69.4
Operations, Maintenance & Administration and Removals	(1.4)	(1.4)	(4.7)
Gross Investment Cost	**18.6**	**18.6**	**64.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**18.6**	**18.6**	**64.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Minden TS
Targeted Start Date: Q2 2017
Targeted In-Service Date: Q4 2020
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Minden TS that are in need of replacement due to degraded condition, obsolescence and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the surrounding area.

Investment Summary:
Built in 1950, Minden TS is a transformer station that supplies load to Orillia Power Generation Corporation and Hydro One Distribution. The two transformers at the station are 60 years old, have obsolete tap changers which are expensive to maintain and uneconomical to upgrade, and are also experiencing a considerable oil leaks which poses an environmental risk.

The project entails the replacement of assets and infrastructure that are deteriorating in condition with new equipment built to current standards. Equipment to be replaced includes: two 230/44kV power transformers and the associated oil spill containment facilities to comply with Ministry of Environment and Climate Change “(MOECC”) requirements, surge arresters, neutral grounding reactors, one station service transformer, disconnect switches, AC and DC station service systems, instrument transformers, and protection and control systems. In addition, infrastructure such as steel support structures, foundations, trenching, control cabling, high and low voltage buswork and power cabling will need to be adjusted or replaced to facilitate replacement of the major assets.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.5	7.5	18.5
Operations, Maintenance & Administration and Removals	(0.3)	(0.5)	(1.3)
Gross Investment Cost	**4.2**	**7.0**	**17.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.2**	**7.0**	**17.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Mohawk TS
Targeted Start Date: Q4 2016
Targeted In-Service Date: Q2 2019
Targeted Outcome: *Operational Effectiveness*

Need:

To address multiple assets at Mohawk TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers.

Investment Summary:

Built in the mid 1950's, Mohawk TS is a transformer station that supplies load to Horizon Utilities Corporation within the City of Hamilton. The oil analysis results for both transformers at Mohawk TS have shown advanced signs of insulation degradation and signs of overheating indicating that there is an increased probability of failure in the near future. The associated protection systems are also deemed end of life and are obsolete.

The project entails the replacement of assets at Mohawk TS with new equipment built to current standards. Equipment to be replaced includes: two power transformers, one station service transformer and the associated protections systems, and the oil spill containment facilities will be upgraded to comply with Ministry of the Environment and Climate Change ("MOECC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would not ensure compliance with environmental and reliability standards.

Witness: Chong Kiat (CK) Ng

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, preserve the reliability of supply to customers in the area, and ensure compliance with NPCC and MOECC requirements.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.9	5.0	14.9
Operations, Maintenance & Administration and Removals	(0.3)	(0.3)	(1.0)
Gross Investment Cost	**4.6**	**4.7**	**13.9**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.6**	**4.7**	**13.9**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement – N.R.C. TS
Targeted Start Date: Q3 2013
Targeted In-service Date: Q3 2017
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address multiple assets at National Research Council ("NRC") TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the early 1950's, NRC TS is a 63 year old transformer station that supplies load to a single customer, the National Research Council in Ottawa. The circuit breakers are inadequately rated and limit the customer's ability to operate their generator due to safety concerns. Oil analysis results on both transformers have repeatedly shown advanced signs of insulation degradation indicating that there is an increased probability of failure in the near term. A commitment was made to the connected customer to replace these units in a timely manner.

The project entails the complete rebuild of the NRC TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: two transformers and the associated oil spill containment facilities to comply with Ministry of Environment and Climate Change ("MOECC") requirements, fifteen circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would not satisfy commitments made to the customer.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate the operational risks associated with operating end of life equipment, maintain system reliability, and demonstrate commitment to the customer.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	7.1	0.7	31.7
Operations, Maintenance & Administration and Removals	0.0	0.0	(0.9)
Gross Investment Cost	**7.1**	**0.7**	**30.8**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**7.1**	**0.7**	**30.8**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Pine Portage SS
Target Start Date: Q4 2016
Targeted In-Service Date: Q4 2020
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Pine Portage SS that are in need of replacement due to poor condition, obsolescence, declining performance and high maintenance costs. These assets directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area; as well as negatively impact transmission capacity and security in Northwestern Ontario.

Investment Summary:
Built in the mid-1950s, Pine Portage SS is a switching station connecting 72MW of generation from the Ontario Power Generation's ("OPG's") Pine Portage generating station to the 115 kV transmission network. Several of the high voltage circuit breakers at Pine Portage SS are deemed end of life due to poor condition, performance and known operating issues. The associated protection and control facilities are also obsolete and deemed end of life.

The project entails the rebuild of the Pine Portage SS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: five oil circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components. The protection and control systems, and other associated auxiliary components currently located in OPG facilities will be relocated to Hydro One Transmission facilities as part of this project. The relocation of Hydro One Transmission assets from OPG facilities will result in a clearly defined demarcation point for asset ownership and operating authority.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs for projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain the reliability to the transmission system in Northwestern Ontario and the OPG generation connected to the transmission system.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	2.0	6.3	19.7
Operations, Maintenance & Administration and Removals	(0.1)	(0.4)	(1.4)
Gross Investment Cost	**1.9**	**5.9**	**18.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**1.9**	**5.9**	**18.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - Richview TS
Targeted Start Date: Q4 2015
Targeted In-Service Date: Q4 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Richview TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Built in the late 1950's, Richview TS is a critical network station that provides 230kV and 115kV switching, transformation of 230kV into 115kV and supplies load to Toronto Hydro ("THESL") within the Greater Toronto Area. Two of the transformers at the station are currently 46 years old and oil analysis results have shown signs of transformer thermal and arcing faults and overheating. This leads to degradation of the internal transformer insulation and indicates that there is an increased probability of failure. The transformers are also experiencing oil leaks that pose a risk to the environment, and contain obsolete tap-changers resulting in an overall deteriorated condition. The protection and control systems on these assets have also passed their expected service life and are obsolete.

The project entails the replacement of assets and infrastructure that are deteriorating in condition with new equipment built to current standards. Equipment to be replaced includes: two 230/27.6kV transformers, disconnect switches, surge arresters, station service transformers and associated transfer schemes, and protection and control systems. In addition, the oil spill containment facilities will be upgraded to comply with Ministry of Environment and Climate Change ("MOECC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life assets, maintain system reliability, and ensure compliance with NPCC and MOECC standards.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	7.8	0.0	26.1
Operations, Maintenance & Administration and Removals	(0.5)	0.0	(1.0)
Gross Investment Cost	**7.3**	**0.0**	**25.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**7.3**	**0.0**	**25.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement – Sheppard TS
Targeted Start Date: Q2 2017
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Sheppard TS that are in need of replacement due to degraded condition, obsolescence and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Built in the early 1960's, Sheppard TS is a 54 year old transformer station that supplies load to Veridian Connections and Toronto Hydro ("THESL") in east Toronto, via two switchyards. Two of the four transformers at the station are 54 years old and oil analysis results shows internal transformer arcing, indicating that there is an increased probability for failure. The low voltage yard supplied by these transformers is a non-standard configuration containing breakers in excess of 50 years old. The protection and control systems have also passed their expected service life and are obsolete.

The project entails the complete replacement of one of the Sheppard TS low voltage switchyards with new standard medium voltage gas insulated switchgear, including two 230kV power transformers. Other equipment to be replaced includes: oil spill containment systems, surge arresters, neutral grounding reactors, disconnect switches, and the protection and control systems. In addition, infrastructure such as steel support structures, foundations, drainage, trenching, control cabling, high and low voltage bus work and power cabling will need to be replaced due to deteriorating condition and to facilitate replacement of the major assets. Selective minor components in the second switchyard will also be upgraded, such as the solid state protection relays which have experienced extremely high failure rates and are end of life.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expenses.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One utilizing historical costs of project of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life assets, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.5	10.0	30.2
Operations, Maintenance & Administration and Removals	(0.7)	(0.7)	(2.1)
Gross Investment Cost	**9.8**	**9.3**	**28.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**9.8**	**9.3**	**28.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Integrated Station Component Replacement - St. Isidore TS
Targeted Start Date: Q1 2016
Targeted In-service Date: Q3 2017
Targeted Outcome: *Operating Effectiveness*

Need:
To address multiple assets at St. Isidore TS that are in need of replacement due to poor condition, obsolescence and high maintenance cost that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in area. It would also negatively impact transmission capacity and security in Eastern Ontario.

Investment Summary:
Built in the late 1960's, St Isidore TS is a 48 year old transformer station that supplies load to Hydro One Distribution and Hydro Ottawa in the Greater Ottawa area. The high voltage switchyard is also a connection point and interface between Hydro One Transmission and Hydro Quebec. The oil analysis results of the two transformers at the station have repeatedly shown signs of internal arcing, indicating that there is an increased probability of failure in the near future. The associated protection and control facilities are also obsolete and have been deemed end of life.

The project entails the replacement of existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: two transformers and associated spill containment systems to comply with Ministry of Environment and Climate Change "(MOECC") requirements, ten circuit breakers, disconnect switches, protection and control systems in accordance with Northeast Power Coordinating Council ("NPCC") requirements, and other associated auxiliary components.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or requirements of the environmental and reliability standards.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and ensure compliance with NPCC and MOECC standards.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	9.1	0.0	26.1
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**9.1**	**0.0**	**26.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**9.1**	**0.0**	**26.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Stanley TS
Targeted Start Date: Q2 2018
Targeted In-Sservice Date: Q2 2020
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Stanley TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in City of Niagara Falls.

Investment Summary:
Built in the late 1950's, Stanley TS is a 58 year old transformer station that supplies load to Niagara Peninsula Energy Inc. in the City of Niagara Falls via two switchyards. The oil analysis results of one of the transformers at the Stanley TS have shown signs of internal arcing indicating that there is an increased probability of failure. All associated protection, control and telecom facilities have also been deemed obsolete and end of life. The existing low voltage switching facilities are non-standard and several breakers have been deemed end of life due to performance, condition and inability to source spare parts for continued maintenance.

The project entails the replacement of assets at Stanley TS with new equipment built to current standards, including: one power transformer, low voltage switchgear consisting of nine breakers, and all associated protection and control facilities. It also includes the upgrade of the oil spill containment facilities to comply with Ministry of Environment and Climate Change ("MOECC") requirements. The replacement of these assets will be accomplished through use of available real estate within the existing station footprint. This project will greatly reduce outage durations and supply constraints which would otherwise negatively impact the local distribution companies.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition or requirements of the environmental and reliability standards.

Basis for Budget Estimate:

The project cost is based on budgetary cost estimates prepared by Hydro One utilizing historical costs of project of similar scope.

Outcome:

To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and ensure compliance with MOECC and NPCC standards.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	0.5	6.5	26.3
Operations, Maintenance & Administration and Removals	0.0	(0.4)	(1.8)
Gross Investment Cost	**0.5**	**6.1**	**24.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.5**	**6.1**	**24.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Strachan TS
Targeted Start Date: Q2 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Customer Focus*, *Operational Effectiveness*

Need:
To address multiple assets at Strachan TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to customers in the area.

Investment Summary:
Built in the early 1950's, Strachan TS is a 65 year old transformer station that supplies load exclusively to Toronto Hydro ("THESL") customers via THESL owned switchgear. One of the transformers at the station is 60 years old and oil analysis results have shown transformer overheating that leads to degradation of the internal transformer insulation, indicating that there is an increased probability of failure. The transformer is also experiencing oil leaks and overall is in a deteriorated condition. There are also disconnect switches on site with limited clearance and is a potential flashover hazard. THESL has requested that the capacity of the transformers be increased in order to meet future load growth in the area.

The project entails the replacement of assets and infrastructure at Strachan TS that are deteriorating in condition with new equipment built to current standards. Equipment to be replaced includes: one 115kV transformer and associated oil spill containment facilities to comply with Ministry of Environment and Climate Change "(MOECC") requirements, switches and other ancillary equipment.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One utilizing historical costs of project of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life assets and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.5	3.0	9.0
Operations, Maintenance & Administration and Removals	(0.4)	(0.2)	(0.6)
Gross Investment Cost	**5.1**	**2.8**	**8.4**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.1**	**2.8**	**8.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Strathroy TS
Targeted Start Date: Q1 2016
Targeted In-Service Date: Q4 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Strathroy TS that are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the early 1950's, Strathroy TS is a 65 year old transformer station that supplies load to Entegrus Power Lines and Hydro One Distribution around the town of Strathroy. In 2013, one of transformers at Strathroy TS failed and was replaced under the demand capital program. This failure necessitates the replacement of the companion unit due to a similar condition and performance rating. Oil analysis results for the transformer have repeatedly shown advanced signs of insulation degradation indicating that there is an increased probability of failure in the near term. Most of the protection and control facilities have also passed their expected service life and are obsolete. Several circuit breakers are beyond their end of life with obsolete parts and operations exceeding the manufacturer's design specification.

The project entails the complete rebuild of Strathroy TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced includes: one power transformer and associated spill containment system facilities to comply with Ministry of Environment and Climate Change ("MOECC") requirements, seven low voltage circuit breakers, associated disconnect switches, nine protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and ensure compliance with the MOECC standard.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.8	0.0	17.8
Operations, Maintenance & Administration and Removals	(0.5)	0.0	(0.5)
Gross Investment Cost	**5.3**	**0.0**	**17.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.3**	**0.0**	**17.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Demand Capital - Power Transformers
Targeted Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: Operational Effectiveness

Need:
To address the failure of power transformers and station service transformers throughout the province, in order to maintain reliability. Not proceeding with this investment will result in declining reliability.

Investment Summary:
Hydro One Transmission owns and operates a fleet of 721 power transformers and a fleet and approximately 580 station service transformers across the province.

This program is supported by the *Operating Spare Transformer Purchases* program (ISD S53). In the unlikely event of a transformer failure, Hydro One Transmission will utilize operating spares to replace failed units. This plan is derived from historical data and performance trends. This investment funds the design, construction and commissioning resources required to the expediently replace failed transformers.

Alternatives:
This program is in response to emergency outages and no alternatives were considered as failure to respond to service interruptions or other emergency situations would result in unacceptable reliability and safety risks

Basis for Budget Estimate:
The program cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of program of similar scope.

Outcome:
Maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	8.2	8.3	16.5
Operations, Maintenance & Administration and Removals	0.2	0.2	0.3
Gross Investment Cost	**8.0**	**8.2**	**16.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.0**	**8.2**	**16.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Minor Component Demand Capital
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address the failure of ancillary station equipment throughout the province, in order to maintain reliability. Not proceeding with this investment will result in declining reliability.

Investment Summary:
Hydro One Transmission owns and operates 292 transmission stations across the province of Ontario.

This program funds the replacement of ancillary station equipment, including but not limited to batteries, switches, and instrument transformers. In the event of equipment failure, Hydro One Transmission will utilize available spares or source new stock to replace failed equipment in a timely manner in order to restore the system to normal operation.

Alternatives:
- Alternative 1: Reactive Replacement (No Inventory); or
- Alternative 2: Status Quo – Replenish inventory.

Alternative 1 was considered and rejected because it does not address the transformer failure in a timely manner and will reduce system reliability. Alternative 2 is the preferred alternative as it addresses equipment failure in a timely manner to maintain system reliability.

Basis for Budget Estimate:
The program cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of programs of similar scope.

Outcome:
Maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	5.0	5.0	10.0
Operations, Maintenance & Administration and Removals	(0.3)	(0.3)	(0.7)
Gross Investment Cost	**4.7**	**4.7**	**9.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.7**	**4.7**	**9.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Operating Spare Transformer Purchases
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: Operational Effectiveness

Need:
To address the failure of power transformers and station service transformers throughout the province, in order to maintain reliability. Not proceeding with this investment will result in declining reliability.

Investment Summary:
Hydro One Transmission currently owns and operates a fleet of 721 power transformers and a fleet of approximately 580 station service transformers across the province.

In order to ensure timely response in the event of a failure, spare transformers are required. The number of spares Hydro One Transmission maintains is based on a probabilistic cost/risk analysis model, consistent with industry standards. The model determines the optimum number of spares required for each group of transformers by taking into consideration several factors: demographics, failure rates, repair/replacement time, internal performance trends and national performance levels supplied by the Canadian Electricity Association. Delivery lead time is also considered in the analysis. This program is supported by the *Demand Capital – Power Transformers* investment (S51) which funds resources to replace failed transformers.

The transformers scheduled for procurement in the test years for use as operating spares will replenish transformers used from system reserves to support failure replacements. Transformers purchased under this program will vary in size and type in order to support the sizes and types of the in-service transformer fleet.

Alternatives:

- Alternative 1: Reactive Replacement (No Inventory); or
- Alternative 2: Status Quo – Replenish inventory.

Alternative 1 was considered and rejected because it does not address the transformer failure in a timely manner and will reduce system reliability. Alternative 2 is the preferred alternative as it addresses equipment failure in a timely manner to maintain system reliability.

Basis for Budget Estimate:

The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:

Maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	8.3	8.4	16.7
Operations, Maintenance & Administration and Removals	(0.1)	(0.1)	(0.2)
Gross Investment Cost	**8.2**	**8.3**	**16.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.2**	**8.3**	**16.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Transformer Protection Replacement due to 2nd Harmonic Misoperations
Targeted Start Date: Q4 2015
Targeted In-Service Date: Q4 2020
Targeted Outcome: Operational Effectiveness

Need:
To mitigate transformer misoperations due to a low 2nd harmonic phenomenon in order to maintain reliability and meet regulatory requirements. Not proceeding will result in non-compliance with regulatory requirements and declining reliability.

Investment Summary:
Transformers experience high inrush current during energization and the inrush currents are typically characterized with high 2nd harmonic. Some transformers can reach up to fifteen times its rated current, causing transformer protection to operate if a proper restraining element is not provided. Relays are traditionally setup to detect 2nd harmonic and block mis-operation. However, recent improvements in transformer core material have significantly reduced the 2nd harmonic component resulting in unnecessary transformer trips during energization. This phenomenon is mainly associated with transformers built in the last 10-15 years.

Failure to address this issue can also lead to a violation of the mandatory NERC standard PRC-004, which requires entities to establish and complete corrective plans related to protection system misoperations.

Over the last 10 years Hydro One has recorded approximately 100 unnecessary transformer protection operations related to the low 2nd harmonic in the transformer inrush current. In order to mitigate these misoperations, a solution which requires use of modern microprocessor based relays (IEDs) was developed. Specific transformers were identified based on the history of previous misoperation and the age of the transformer. This investment requires 80 protections of older vintage relays to be updated to the latest Hydro One transformer protections standard using modern IED. This program will continue over a 5 year period.

Also, this investment will reduce OM&A cost associated with the mitigation and analysis of misoperations.

Alternatives:
Two altrenatives were considered:

- Alternative 1: Continuing to reactively maintain the assets (Status quo); or
- Alternative 2: Replacement of the assets.

Alternative 1 was considered and rejected due to the negative impact on reliability and the potential NERC noncompliance issues. Alternative 2 is the preferred alternative as it maintains reliability and is compliant with NERC standards.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To maintain system reliability and comply with regulatory requirements.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.6	4.6	16.5
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**4.6**	**4.6**	**16.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.6**	**4.6**	**16.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name*:* Replace Legacy SONET Systems
Targeted Start Date: Q1 2017
Targeted In-Service Date: Q4 2024
Targeted Outcome: Operational Effectiveness

Need:
To maintain system reliability, and meet compliance standards, including the Transmission System Code through maintaining protection, control and telecom functionality. Not proceeding with this investment will have an adverse impact on system reliability, compliance with mandatory standards, ability to manage and execute large construction programs with unreliable protections, and could lead to significant safety incidents.

Investment Summary:
The fleet of over 200 SONET ADM (add/drop multiplexers) and other associated communication devices has been in service for close to 20 years in support of protection, control and telecom applications of Hydro One's transmission system. This communication technology has reached end of life. It is no longer supported by manufacturers and it is increasingly difficult to source spare parts. The installed-base of SONET equipment is being phased out by major communication carriers and other private communication networks operators.

While Hydro One is able to maintain the legacy SONET system in the near term, the company's ability to deploy new applications that are characteristic of modern grid and require IP connectivity in a cost effective manner is compromised.

Technical evaluation of available technologies will be part of this investment and once the new technology platform which satisfies the technical requirements is determined, the multi year deployment will begin. Based on volume and complexities of change over, it is anticipated that 7 to 8 years will be required for orderly migration to the new networking platform. As the network undergoes migration there will be a period of overlap when both existing and new platform will need to be operated and maintained at the same time.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 1 was considered and rejected due to the condition of the assets, increased risk of failure, and diminishing manufacturers' support. Alternative 2 is the preferred alternative as it addresses the asset condition, reduces risk of failure, will allow for manufacturers' support.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To maintain system reliability and comply with regulatory requirements.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	2.1	5.3	112.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**2.1**	**5.3**	**112.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**2.1**	**5.3**	**112.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name*:* Physical Security for Critical Stations (Non CIP-014)
Targeted Start Date: Q1 2017
Targeted In-Service Date: Q4 2020
Targeted Outcome: *Operating Effectiveness*

Need:
To maintain system reliability and the safe delivery of electricity through securing critical stations to Hydro One's transmission system and the Bulk Electric System. Not proceeding with this investment would result in unresolved security concerns that result in safety concerns and may negatively impact system reliability.

Investment Summary:
Hydro One has identified 18 stations which are critical to the Hydro One system, that were outside the scope for NERC CIP-014 (North American Electric Reliability Corporation – Critical Infrastructure Protection). These stations are crucial to the reliability of the Ontario grid. As such, these stations will be protected to ensure safe and reliable operations of the Bulk Electric System.

Threat Risk Assessment (TRA) is a detailed process that evaluates a station for security gaps, which is performed by security specialists and is verified by an external 3rd party. The TRA outlines the security deficiencies and recommend solutions to mitigate risk. This program will implement physical security measures based on the recommendations of the TRA at these critical stations. Providing adequate physical security to critical Hydro One stations will ensure operational effectiveness, as well as grid resiliency and reliability to Hydro One customers.

Alternatives:
Two alternatives were considered:

- Alternative 1: Continue without addressing security deficiencies (status quo); or
- Alternative 2: Implement physical security measures.

Alternative 1 was considered and rejected due to its failure to address security gaps identified through the TRA, creating unnecessary risk to system reliability. Alternative 2 is the preferred alternative as it addresses security issues that may jeopardize system reliability and safety.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
Maintain system reliability and safe delivery of electricity.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.0	5.0	18.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**5.0**	**5.0**	**18.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.0**	**5.0**	**18.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name*:* CIP V6 Transient Cyber Assets & Removable Media
Targeted Start Date: Q2 2016
Targeted In-Service Date: Q3 2018
Targeted Outcome: *Operational Effectiveness, Regulatory Compliance*

Need:
To address cyber security concerns in order to maintain system reliability and meet regulatory compliance requirements. Not proceeding with this investment would result in non-compliance of North American Electric Reliability Corporation (NERC) cyber security requirements and jeopardize system reliability.

Investment Summary:
NERC - Critical Infrastructure Protection (CIP) cyber security requirements are mandatory for all North American utilities for regulatory compliance. The new version 6 requirement of CIP-010-2 R4 for Transient Cyber Assets and Removable Media has a compliance date of April 1, 2017. This investment is for the deployment of a compliant solution for Hydro One.

The solution protects the company's critical Bulk Electric System (BES) Cyber Assets from external cyber threats introduced through transient devices and removable media such as laptops and USB drives. Hydro One will be deploying the transient compliant solution for use at all stations. This approach will ensure compliance, operational effectiveness, and good utility security practice for the safe and reliable operation of Hydro One equipment.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue with current state (status quo); or
- Alternative 2: Implement transient cyber asset security.

Alternative 1 was considered and rejected due to non-compliance with NERC cyber security standards and increased risk to security and system reliability. Alternative 2 is the preferred alternative as it complies with the security standards and helps maintain system reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:

This investment will result in regulatory compliance with NERC security standards, while maintaining system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	2.0	10.0	12.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**2.0**	**10.0**	**12.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**2.0**	**10.0**	**12.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name*:* PSIT Cyber Equipment EOL
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness, Regulatory Compliance*

Need:
To address cyber security threats in order to maintain reliability and meet regulatory requirements under the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards. Not proceeding with this investment will result in non-compliance of regulatory requirements and jeopardizes system reliability.

Investment Summary:
NERC CIP cyber security requirements are mandatory for all North American utilities for regulatory compliance. The cyber security threat landscape is dynamic, and NERC CIP requirements are reflective of these changes. This investment is to address End of Life (EOL) Cyber Security equipment for the Power System Information Technology (PSIT) department used specifically at Hydro One Control Centers. This will position Hydro One to address evolving cyber threats to ensure ongoing regulatory compliance, reliability and operational effectiveness of the systems controlling the Ontario grid.

Cyber security equipment has a shorter lifespan than traditional Protection & Control (P&C) equipment. This is mainly attributable to the evolving cyber security threats, and the corresponding changes to the NERC regulatory requirements. Some systems identified for replacement include routers, servers, intrusion detection/prevention systems, storage, firewall, and software.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue with current equipment (status quo); or
- Alternative 2: Replacement of equipment and systems as outlined above.

Alternative 1 was considered and rejected due to its failure to address obsolete and unsupported systems that cannot meet regulatory obligations or provide adequate cyber security protection, which will result in non-compliance and jeopardizes system reliability. Alternative 2 is the preferred alternative as it meets regulatory compliance obligations and maintains reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
This investment will result in compliance of regulatory requirements, while maintaining system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	5.0	6.0	11.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**5.0**	**6.0**	**11.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.0**	**6.0**	**11.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name*:* CIP-014 Physical Security Implementation
Targeted Start Date: Q1 2017
Targeted In-Service Date: Q4 2020
Targeted Outcome: *Operating Effectiveness, Regulatory Compliance*

Need:
To improve physical security at Hydro One critical stations in order to comply with regulatory requirements, maintain system reliability and provide additional public safety. Not proceeding with this investment will result in unsecure stations, with unnecessary safety and reliability risks as well as non-compliance with regulatory requirements.

Investment Summary:
North American Electric Reliability Corporation - Critical Infrastructure Protection (NERC CIP) cyber security requirements are mandatory for all North American utilities for regulatory compliance. The requirement of CIP-014 addresses physical security for transmission stations which if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or cascading effects to the Bulk Electric System. This investment is for the deployment of a compliant solution for Hydro One.

Hydro One has identified 26 stations that are subject to CIP-014 requirements.

Threat Risk Assessment (TRA) is a detailed process that evaluates a station for security gaps. The assessment is performed by security specialists and is verified by an external 3rd party. The TRA outlines the security deficiencies and recommend solutions to mitigate risks. This investment will implement physical security measures, based on the recommendations of the TRA, for these critical stations. Providing adequate physical security to Hydro One critical stations will ensure operational effectiveness, as well as grid resiliency and reliability to Hydro One customers.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to operate under current security conditions (status quo); or
- Alternative 2: Implement security measures as recommended under the TRA.

Alternative 1 was considered and rejected due to its failure to adequately secure critical stations, risk to system reliability and safety and non-compliance with CIP-014 requirements. Alternative 2 is the preferred alternative as it complies with CIP-014, improves security, and helps maintain reliability and safety.

Basis for Budget Estimate:

The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:

This investment will comply with regulatory requirements, while ensuring adequate physical protection to stations in order to maintain reliability and public safety.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	6.0	6.0	24.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**6.0**	**6.0**	**24.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**6.0**	**6.0**	**24.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name*:* NERC CIP V6 – Low Impact Facilities
Targeted Start Date: Q2 2016
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness, Regulatory Compliance*

Need:
To address physical and electronic security at Low Impact facilities in order to meet North American Electric Reliability Corporation – Critical Infrastructure Protection (NERC CIP) cyber security requirements. Not proceeding with this investment would result in non-compliance with security requirements and jeopardize system reliability.

Investment Summary:
NERC CIP cyber security requirements are mandatory for all North American utilities for regulatory compliance. The new version 6 requirement of CIP-003-6 R2 addresses Physical Security and Electronic Access Control to Low Impact facilities and has a December 1, 2018 compliance date. This investment is for the deployment of a compliant solution for Hydro One to Low Impact facilities across the province.

Hydro One has identified 69 Low Impact facilities within 61 stations across the province. Given the high number of facilities and their wide geographic distribution, a centrally managed, standard implementation for physical security controls is necessary to both minimize ongoing sustainment costs and to maintain the integrity of needs-based physical access control. A subset of the Low Impact facilities also require the implementation of dial-up authentication (where applicable) to address Electronic Access Controls. Providing adequate physical and electronic access security to these stations will ensure operational effectiveness, as well grid resiliency and reliability to Hydro One customers.

Alternatives:
Two alternatives were considered:
Alternative 1: Continue with current state (status quo); or
Alternative 2: Implement transient cyber asset security.

Alternative 1 was considered and rejected due to non-compliance with NERC standards and increased risk to security and system reliability. Alternative 2 is the preferred alternative as it complies with the regulatory requirements, while maintaining system reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
This investment will result in compliance with regulatory requirements, while providing physical and electronic security to Hydro One sites to aid in maintaining system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.0	5.0	10.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**5.0**	**5.0**	**10.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.0**	**5.0**	**10.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Transmission Site and Facilities Infrastructure
Start Date: Ongoing Program
In-service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
This investment is required to address end of life infrastructure, functional deficiencies, and safety concerns in the transmission station building infrastructure. Not proceeding with this project will result in diminished functionality of the station building infrastructure and increased risk to employee safety and system reliability.

Investment Summary:
Transmission station building infrastructure is comprised of station heating, ventilation and air conditioning ("HVAC") systems, water supply systems, and building components. These systems provide infrastructure and support services for buildings designed to house Hydro One Transmission staff and in some cases, electrical assets (i.e. protection, control and telecom equipment).

This program includes HVAC system replacements and general building renovations, including building roof and water supply upgrades. Investments are identified based on end of life determination which includes asset condition assessments, inspections, known deficiencies, system needs, consequences of failure and regulatory requirements, where applicable.

Alternatives:
Two alternatives were considered:
Alternative 1: Status Quo; or
Alternative 2: Complete the program as outlined above.

Alternative 1 was considered and rejected as it does not address the needs of the building infrastructure. Alternative 2 is the preferred alternative which will address building infrastructure deficiencies, mitigates employee safety risks, and maintains system reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
This program will address deficiencies in the station building infrastructure to mitigate to safety risks and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	6.7	6.7	13.4
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**6.7**	**6.7**	**13.4**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**6.7**	**6.7**	**13.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: C22J/C24Z/C21J/C23Z Line Refurbishment
Targeted Start Date: Q4 2014
Targeted In-Service Date: Q3 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address the condition of the structures on the 230 kV circuits C22J/C24Z & C21J/C23Z from Chatham SS to Sandwich Junction, C21J/C22J from Sandwich Junction to Keith TS and C23Z/C24Z from Sandwich Junction to Lauzon TS. Not completing this work will result in an increase in the probability of future structure failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Structure failures also create a risk to public safety.

Investment Summary:
This project addresses the refurbishment of the 230 kV transmission circuits C21J, C22J, C23Z and C24Z that provide critical supply to the Chatham, Windsor and surrounding area loads, and support the interconnection with Michigan. A structural analysis study, on the steel structures supporting circuits C22J and C24Z from Chatham SS x Sandwich JCT (222 structures) carried out by Engineering in 2010, indicates that these structures need to be refurbished to restore their condition and extend their life. Similarly, 63 steel structures that support circuits C21J and C22J, from Sandwich JCT to Keith TS, are of the same vintage and in similar condition.

The structure refurbishment work on these 285 steel towers includes: the replacement of steel structure members and associated hardware, which are loaded beyond 95% of their capacity; replacement of end-of-life or damaged insulators; and complete tower coating/painting to prevent any further deterioration due to corrosion and extend their life by approximately 30-40 years. In some cases, the damage to the structures is so significant that repair may not be feasible and complete tower replacement may be warranted. In addition, 7 wood poles on these circuits are in very poor condition and require replacement.

The galvanized steel shieldwire on these circuits have also reached their expected end-of-life and much of it has already been replaced. The remaining galvanized steel shieldwire on both C22J/C23Z and C21J/C24Z from Chatham TS x Sandwich Jct x Keith TS (approximately 174 km) has also reached end-of-life and is to be replaced.

In addition, from Sandwich JCT to Lauzon TS, there are approximately 56 structures supporting circuits C23Z and C24Z that are 44 years old and exhibiting signs of significant rust corrosion. These structures are also to be tower-coated/painted to prevent further structural deterioration.

Witness: Chong Kiat (CK) Ng

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 considered and involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To mitigate the safety concerns to workers and the public from potential structure failures and maintain system reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	21.1	2.8	51.6
Operations, Maintenance & Administration &Removals	(2.5)	(0.3)	(4.3)
Gross Investment Cost	**18.5**	**2.5**	**47.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**18.5**	**2.5**	**47.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: D2L (Dymond x Upper Notch) Line Refurbishment
Targeted Start Date: Q3 2015
Targeted In-Service Date: Q2 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To address the condition of the conductor on the 115 kV circuit D2L from Dymond TS to Upper Notch Junction. Not completing this work will result in an increase in the probability of failure that will adversely increase the risk to public safety and impact the supply reliability to a number of industrial and residential customers in the region.

Investment Summary:

The existing conductor, insulators, hardware and the shieldwire on circuit D2L are part of the original line built 86 years ago. These conductors are manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. Selected conductors on these circuits have been verified to be at their end-of-life via conductor sampling and laboratory testing.

Conductor tests reveal that the tensile strength and ductility of D2L have deteriorated to the extent that the conductor has reached its end-of-life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project will result in a rebuild of circuit D2L between Dymond TS and Upper Notch Junction, replacing existing degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the replacement of the existing ACSR conductors with new similar size conductors; and the replacement of shieldwire, insulators and all associated hardware on the 77 kilometer section of the line between Dymond TS and Upper Notch Junction. In addition, all structures will be refurbished as required.

Witness: Chong Kiat (CK) Ng

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To reduce the safety concerns to workers and the public from potential component failures. Maintain system reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	9.5	0.0	35.3
Operations, Maintenance & Administration &Removals	(1.1)	0.0	(3.7)
Gross Investment Cost	**8.4**	**0.0**	**31.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.4**	**0.0**	**31.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: C1A/C2A/C3A Line Refurbishment
Targeted Start Date: Q1 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address the condition of the conductor on the 115 kV circuits C1A/C2A/C3A from Cameron Falls GS to Alexander GS. Not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:

The existing conductor, insulators, hardware and the shieldwire on circuit C1A/C2A are part of the original line built over 92 years ago. The majority of these conductors were manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension.

Selected conductors on these circuits have been verified to be at their end-of-life via conductor sampling and laboratory testing. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductor on circuits C1A and C2A is of ACSR construction.

Conductor tests reveal that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end-of-life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. The insulators, hardware and shieldwire on this line are also approaching end of life.

The conductor on circuit C3A is copper and is part of the original line built about 92 years ago. This obsolete aged conductor has deteriorated and reached end-of-life and will be replaced with similar size standard ACSR conductor.

Witness: Chong Kiat (CK) Ng

The project will include a rebuild of circuits C1A/C2A/C3A between Cameron Falls GS and Alexander GS, replacing existing degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes the replacement of the existing conductor with a new similar size conductor; as well as the replacement of shieldwire, insulators and all associated hardware on the 8 kilometer section of the line between Cameron Falls GS and Alexander GS. All of the other structures will also be refurbished if required.

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To reduce the safety concerns to workers and the public from potential component failures and to maintain system reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	2.0	4.0	6.1
Operations, Maintenance & Administration &Removals	(0.2)	(0.5)	(0.8)
Gross Investment Cost	**1.8**	**3.5**	**5.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**1.8**	**3.5**	**5.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: N21W/N22W Line Refurbishment
Targeted Start Date: Q2 2017
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address the condition of the steel structures on the 230 kV circuits N21W/N22W from Sarnia Scott TS to Buchanan TS. Not completing this work will result in an increase in the probability of future structure failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Structure failures also create a risk to public safety.

Investment Summary:
N21W/N22W line is a 230 KV transmission line between Sarnia Scott TS and Buchanan TS. It is about 104 km long and was built in 1959. The line is primarily composed of X1 tower family which has historically failed every eight to ten years since this line was built. The last two failure investigations done in 2002 and 2011 concluded that the failures occurred due to the high wind speeds at approximately 120 km/h. These structures do not meet either minimum Hydro One security class "B" or CSA C22.3 No.1 standard. This line has experienced seven major failures in the past 57 years due to its substandard steel structures. In order to maintain a safe and reliable supply of electricity to customers throughout the Chemical Valley in Sarnia area it is recommended that these structures to be refurbished and reinforced.

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 considered involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:

To address safety concerns to workers and the public from future structure failures and maintain system reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.7	13.5	26.9
Operations, Maintenance & Administration & Removals	(0.6)	(1.6)	(3.3)
Gross Investment Cost	**4.1**	**11.9**	**23.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.1**	**11.9**	**23.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: B5G/B6G Line Refurbishment
Targeted Start Date: Q3 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 115 kV circuits B5G and B6G from Burlington TS to Enbrg Westover CTS. Not completing this work will increase the probability of future line failures which will increase the risk to public safety and adversely impact the supply reliability to a number of industrial and residential customers in the region.

Investment Summary:
The existing conductor, insulators, hardware and the shieldwire on circuits B5G and B6G are part of the original line built 65 years ago. These conductors are manufactured with aluminum strands surrounding steel strands (core). They are also known as aluminium conductor steel-reinforced cable ("ACSR conductor"). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. Selected conductors on these circuits have been verified to be at their end-of-life via conductor sampling and laboratory testing.

Conductor tests reveal that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end-of-life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project involves to rebuilding the B5G and B6G circuit between Burlington TS and Enbrg Westover CTS, and the replacement of existing degraded infrastructure with new equipment built to current standards. Equipment to be replaced in this project includes: the existing ACSR conductor with a new ACSR conductor, shieldwire, insulators, and all associated hardware on the 93 circuit kilometer section between Burlington TS and Enbrg Westover CTS. All other structures on this circuit will also be refurbished if required.

Alternatives:
The alternatives considered were:
- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 considered involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain system reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.0	13.0	18.9
Operations, Maintenance & Administration and Removals	(0.6)	(1.6)	(2.2)
Gross Investment Cost	**4.4**	**11.4**	**16.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.4**	**11.4**	**16.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: D2L (Upper Notch x Martin River) Line Refurbishment
Targeted Start Date: Q2 2017
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address the condition of the conductor on the 115 kV circuit D2L from Upper Notch Junction to Martin River Junction. Not completing this work will increase the probability of future line failures which will increase the risk to public safety and adversely impact the supply reliability to a number of industrial and residential customers in the region. .

Investment Summary:
The existing conductor, insulators, hardware and the shieldwire on circuit D2L are part of the original line built between 1930 and 1947. These conductors were manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. Selected conductors on these circuits have been verified to be at their end-of-life via conductor sampling and laboratory testing.

Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductor on circuit D2L is of ACSR construction.

Conductor tests done on D2L revealed that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end-of-life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. The insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project will result in a rebuild of circuit D2L between Upper Notch Junction and Martin River Junction, replacing existing degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the replacement of the existing conductor with a new similar size conductor; and shieldwire, insulators and all associated hardware on the 58 kilometer section of the line between Upper Notch Junction and Martin River Junction. In addition, all structures will be refurbished as required.

Witness: Chong Kiat (CK) Ng

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain system reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	20.8	24.0	49.1
Operations, Maintenance & Administration &Removals	(2.5)	(2.9)	(5.9)
Gross Investment Cost	**18.3**	**21.1**	**43.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**18.3**	**21.1**	**43.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: B3/B4 Line Refurbishment
Targeted Start Date: Q3 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 115 kV circuits B3 and B4 from Horning Mountain JCT to Glanford JCT. Not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:

The existing conductor, insulators, hardware and the shieldwire on circuits B3 and B4 are part of the original line built 101 years ago. These conductors are manufactured with copper strands and have lost their tensile strength due to annealing. In addition, these conductors are obsolete and there is no hardware readily available to repair them when they fail. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductors on circuits B3 and B4 are of copper construction.

The project proposed to rebuild the B3 and B4 circuit between Horning Mountain JCT and Glanford JCT, and to replace existing degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the replacement of the existing copper conductor with an equivalent ACSR conductor; and shieldwire, insulators and all associated hardware on the 22 circuit kilometer section between Horning Mountain JCT and Glanford JCT.

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate the safety concerns to workers and the public from potential component failures and to maintain system reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.0	7.2	8.2
Operations, Maintenance & Administration and Removals	(0.1)	(0.8)	(1.0)
Gross Investment Cost	**0.9**	**6.4**	**7.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.9**	**6.4**	**7.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: A8K/A9K Line Refurbishment
Targeted Start Date: Q1 2018
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 115 kV circuits A8K and A9K from A8K Str. 141 JCT to Ramore JCT. Not completing this work will increase the probability of future line failures which will increase the risk to public safety and adversely impact the supply reliability to a number of industrial and residential customers in the region.

Investment Summary:
The existing copper conductor, insulators, hardware and the shieldwire on circuits A8K and A9K are part of the original line built 80 years ago. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. These conductors are manufactured with copper strands and have lost their tensile strength due to annealing. In addition, these conductors are obsolete and there is no hardware readily available to repair them when they fail.

Sample tests of this conductor type has revealed that the tensile strength has deteriorated to the extent that the conductor has reached its end-of-life, making the conductor susceptible to failure from loading caused by wind and ice. In addition, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project will result in a rebuild of circuit A8K and A9K between A8K Str. 141 JCT and Ramore JCT, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the replacement of the existing copper conductor with an equivalent ACSR conductor; and shieldwire, insulators and all associated hardware on the 63 circuit kilometer section between A8K Str. 141 JCT and Ramore JCT.

Witness: Chong Kiat (CK) Ng

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain customer delivery reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	0.5	7.5	19.3
Operations, Maintenance & Administration and Removals	(0.1)	(0.9)	(2.3)
Gross Investment Cost	**0.4**	**6.6**	**17.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.4**	**6.6**	**17.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: A7L/R1LB & 57M1 Line Refurbishment
Targeted Start Date: Q2 2018
Targeted In-Service Date: Q4 2021
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 115 kV circuits A7L, R1LB and 57M1 from Alexander B JCT to Nipigon JCT. Not completing this work will result in an increase in the probability of failures that will adversely increase the risk to public safety and impact the supply reliability to a number of industrial and residential customers in the region.

Investment Summary:

The existing conductor, insulators, hardware and the shieldwire on circuits A7L, R1LB and 57M1 are part of the original line built 92 years ago. These conductors are manufactured with copper strands and have lost their tensile strength due to annealing. In addition, these conductors are obsolete and there is no hardware readily available to repair them when they fail. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels.

Sample tests of this conductor type has revealed that the tensile strength has deteriorated to the extent that the conductor has reached its end-of-life, making the conductor susceptible to failure from loading caused by wind and ice. In addition, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project will result in a rebuild of circuit A7L, R1LB and 57M1 between Alexander B JCT and Nipigon JCT, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the existing copper conductor with an equivalent ACSR conductor; and shieldwire, insulators and all associated hardware on the 210 circuit kilometer section between Alexander B JCT and Nipigon JCT.

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain customer delivery reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.0	23.3	78.6
Operations, Maintenance & Administration and Removals	(0.1)	(2.8)	(9.5)
Gross Investment Cost	**0.9**	**20.5**	**69.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.9**	**20.5**	**69.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: K1/K2 Line Refurbishment
Targeted Start Date: Q3 2018
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 115 kV circuits K1 and K2 from Kirkland Lake TS to Holloway Holt JCT. Not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:
The existing conductor, insulators, hardware and the shieldwire on circuits K1 and K2 are part of the original line built 89 years ago. These conductors were manufactured with copper strands and have lost their tensile strength due to annealing. In addition, these conductors are obsolete and there is no hardware readily available to repair them when they fail. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels.

Sample tests of this conductor type has revealed that the tensile strength has deteriorated to the extent that the conductor has reached its end-of-life, making the conductor susceptible to failure from loading caused by wind and ice. In addition, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

This project proposes to rebuild of circuit K1 and K2 between Kirkland Lake TS and Holloway Holt JCT, and to replace existing and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: existing copper conductor with an equivalent ACSR conductor; and shieldwire, insulators and all associated hardware on the 59 circuit kilometer section between Kirkland Lake TS and Holloway Holt JCT.

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain customer delivery reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.0	8.4	17.8
Operations, Maintenance & Administration and Removals	(0.1)	(1.0)	(2.1)
Gross Investment Cost	**0.9**	**7.4**	**15.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.9**	**7.4**	**15.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: E1C Line Refurbishment
Targeted Start Date: Q3 2018
Targeted In-Service Date: Q4 2020
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 115 kV circuit E1C from Falls TS to Slate Falls DS. Not completing this work will result in an increase in future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:
Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductors on circuit E1C are of ACSR construction.

These conductors are manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. Selected conductors on these circuits have been verified to be at their end-of-life via conductor sampling and laboratory testing.

The existing conductor, insulators, hardware and the shieldwire on circuit E1C are part of the original line built 77 years ago. Conductor tests reveal that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end-of-life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project will result in a rebuild of circuit E1C between Falls TS and Slate Falls DS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the existing ASCR conductor with a new ACSR conductor; and shieldwire, insulators and all associated hardware on the 149 circuit kilometer section between Falls TS and Slate Falls DS. In addition, all structures will be refurbished as required.

Witness: Chong Kiat (CK) Ng

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.0	14.5	44.5
Operations, Maintenance & Administration and Removals	(0.1)	(1.7)	(5.3)
Gross Investment Cost	**0.9**	**12.8**	**39.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.9**	**12.8**	**39.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: D6V/D7V Line Refurbishment
Work Execution Period: Q2 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 230 kV circuits D6V/D7V from Guelph North JCT to Fergus JCT. Not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failure also creates a risk to public safety.

Investment Summary:
These conductors were manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor’s strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. Selected conductors on these circuits have been verified to be at their end-of-life via conductor sampling and laboratory testing.

Conductor tests reveal that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end-of-life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. In addition, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project proposes to rebuild the circuits D6V/D7V between Guelph North JCT and Fergus JCT, replacing existing degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the existing ASCR conductor with a new ACSR conductor; and shieldwire, insulators and all associated hardware on the 19 circuit kilometer section between Guelph North JCT and Fergus JCT.

Witness: Chong Kiat (CK) Ng

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 considered involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain customer delivery reliability and line performance.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	3.0	6.4	9.4
Operations, Maintenance & Administration and Removals	(0.4)	(0.7)	(1.1)
Gross Investment Cost	**2.6**	**5.7**	**8.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**2.6**	**5.7**	**8.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: D2H/D3H Line Refurbishment
Targeted Start Date: Q2 2018
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address the deteriorating condition of the conductors on the 115 kV circuits D2H/D3H from Calder JCT to Greenwater JCT & Hwy 634 JCT to Island Falls JCT. Not completing this work will increase the probability of line failures which will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:

The existing conductor, insulators, hardware and the shieldwire on circuits D2H/D3H are part of the original line built 83 years ago. These conductors are manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. Selected conductors on these circuits have been verified to be at their end of life via conductor sampling and laboratory testing. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductors on circuits D2H/D3H are of ACSR construction.

Conductor tests reveal that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end-of-life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. In addition, the insulators, hardware and shieldwire on this line are also approaching end-of-life.

The project proposes to rebuild the D2H/D3H circuit between Calder JCT and Greenwater JCT & Hwy 634 JCT and Island Falls JCT, and to replace the existing degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: the existing ASCR conductor with a new ACSR conductor; and shieldwire, insulators and all associated hardware on the 59 circuit kilometer section between Calder JCT and Greenwater JCT & Hwy 634 JCT and Island Falls JCT. In addition, all structures will be refurbished as required.

Alternatives:
The alternatives considered were:

- Alternative 1: Continue to run the assets to failure;
- Alternative 2: Build new structure; or
- Alternative 3: Refurbish the existing assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 involved building new structures to replace existing structures. This alternative was rejected due to significantly higher costs in comparison with refurbishing existing structures. Alternative 3 is the preferred alternative as it is a more cost effective option and addresses the deteriorated condition of the assets.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To mitigate safety concerns to workers and the public from potential component failures and to maintain system reliability.

Costs:

($ Millions)	**2017**	**12.5**	**Total**
Capital* and Minor Fixed Assets	1.0	14.2	29.4
Operations, Maintenance & Administration and Removals	(0.1)	(1.7)	(3.5)
Gross Investment Cost	**0.9**	**12.5**	**25.9**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.9**	**12.5**	**25.9**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: 2017-2018 TX Wood Pole Replacements
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address wood pole structures in deteriorated condition that have reached end of life. Replacements will focus on the structures that are the highest risk to reliability and safety. Not proceeding with this investment would result in increased risk of structure failures, negatively impacting public safety and transmission system reliability, especially since the majority of wood pole lines are on single supply and will directly impact customers.

Investment Summary:
Hydro One Transmission currently owns and manages approximately 42,000 wood pole structures spanning about 7,000 route kilometers. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. Wood structures deteriorate over time; the rate of deterioration depends on location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location.

Replacement candidates are based on condition assessments. Wood pole structure condition is collected from visual inspections of the various components that make up the structure including the cross-arms. Visual inspections include both a detailed helicopter inspection to assess the upper area of wood structures and a ground line inspection to assess the lower part of wood structures. In addition to the visual inspections, other diagnostic testing that focuses on internal rot and wood pecker holes, is used to assess condition. Representative samples of wood poles are drilled once they meet a certain age criteria to determine the presence of internal rot.

For the Gulfport type wood structures, the small wood pole cross-arms that support the conductor are known to have internal premature rotting and have caused several structure failures in the past. Many of these structures are contained within the critical east west tie line across the northern part of Ontario to Manitoba.

Wood poles are deemed to be end of life when: the surface condition degrades and the poles are no longer climbable; there is significant pole top rot; or where wood pecker holes have weakened the strength of the pole. Poles that are drill tested that have 2 inches or less of solid circumferential wood remaining from internal rot will be replaced as they have fallen below their required design strength. All wood poles and components are replaced when their condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions.

The wood pole structures scheduled for replacement in the test years will be replaced with new wood pole or composite structures. The proposed plan will be to replace approximately 850 wood poles in each of the test years 2017 and 2018. This represents an average annual replacement rate 2%. This rate of replacement has been able to keep pace with end of life wood poles identified through inspections as well as address other known wood pole deficiencies, such as the Gulfport structures, on the transmission system.

Alternatives:
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replace the assets.

Alternative 1 was considered and rejected due to the condition of the poles and increased risk of failure. Alternative 2 is the preferred alternative as it mitigates reliability risk and maintains system reliability. It also mitigates the risk of employee and public safety arising from pole failure.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
This plan will maintain reliability, and reduce safety risk to employees and the public from failing structures by replacing a total of approximately 1,700 wood pole structures over the test years.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	40.1	40.1	80.1
Operations, Maintenance & Administration and Removals	(4.8)	(4.8)	(9.6)
Gross Investment Cost	**35.3**	**35.3**	**70.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**35.3**	**35.3**	**70.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Steel Structure Coating
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To extend the service life of steel structures by restoring the galvanized coating that protects the structures from corrosion. This will maintain reliability, address possible employee and public safety concerns and avoid additional capital replacement from further deterioration of the assets. Not proceeding with this investment will result in further deterioration of the steel structures, impacting system reliability as well as employee and public safety and eventually lead to the replacement of the structures at a greater cost.

Investment Summary:
Hydro One Transmission currently owns and manages approximately 52,000 steel structures. The steel used in these structures is manufactured with a zinc-based galvanized coating to protect steel towers from corrosion. Over time the galvanized zinc coating corrodes, exposing the bare steel underneath to the environment. This results in the bare steel beginning to corrode and typically at a much faster rate. If the tower is not painted with a galvanized coating and corrosion is allowed to continue, the steel components will begin to lose mechanical strength due to excessive metal loss resulting in the structure no longer meeting Hydro One Transmission design standards.

Based on field sample testing and a study conducted by Electrical Power Research Institute (EPRI), steel towers will lose their protective zinc in 35~65 years after installation in high corrosive areas/zones in Ontario. Furthermore they would lose 10% of their metal in the following 30~60 years. At this stage, structures are no longer able to withstand the original design loads and either a major refurbishment or complete tower replacement would be required. Hydro One is currently targeting these structures for tower coating in high corrosive areas. Hydro One coating program is established in conjunction with sample field measurements and ongoing condition assessments on steel towers over the test years.

The International Organization for Standardization (ISO) has established six atmospheric corrosivity categories. In accordance with ISO 12944 and a study completed by EPRI, the province of Ontario is divided into four corrosion zones ranging from C2 to C5. As described in Exhibit B1, Tab 2, Schedule 6, Hydro One currently is targeting structures in the two highest corrosion zones under its tower coating program.

Reinstating the protective coating by painting presents the lowest life cycle cost and technically could be carried out on an ongoing basis to extend the life of these assets in perpetuity. The proposed plan will be to reinstate the protective coating on 1,250 and 1,600 steel structures in the 2017 and 2018 test years respectively.

Alternatives:
Alternative 1: Continue to maintain assets at historical rate (status quo); or
Alternative 2: Apply zinc based galvanized coating to an increased number of steel structures.

Alternative 1 was considered and rejected due to asset condition, the number of assets in need of a new protective coating, increased risk of failure, and the high cost of replacing the steel structures. Alternative 2 is the preferred alternative as it addresses the assets in need, maintains reliability and minimizes the expenses incurred.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To maintain reliability, address employee and public safety concerns and minimize future costs by extending the life of the assets.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	42.5	54.4	96.9
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**42.5**	**54.4**	**96.9**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**42.5**	**54.4**	**96.9**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Steel Structure Foundation Refurbishment Program
Targeted Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address steel structure foundations in deteriorated condition by refurbishing those that are the highest risk to system reliability. Not proceeding with this investment will result in an increased risk failure, including structure collapse, impacting public safety and system reliability.

Investment Summary:
Hydro One Transmission currently owns and manages approximately 52,000 steel structures which are supported by a foundation, in most cases grillage (buried steel) or concrete.

From the early 1900s into the 1960s, most lattice steel structures were constructed with a grillage (buried steel) foundation. Concrete foundations were introduced as the new standard for transmission line lattice steel structures starting in the 1960s with the transition to the new standard by 1970. There are approximately 31,000 grillage footings and approximately 3,100 guyed structures which rely on the integrity of the steel grillage and anchors to support these structures. The majority of these installations are greater than 50 years old.

Steel tower grillage foundations and anchors are fabricated with a zinc-based galvanized coating which protects the underlying steel against corrosion. Coating life can vary considerably depending on the surrounding environment. Once the galvanizing has been depleted, the underlying bare steel begins to corrode and typically at a rate much faster than the galvanized coating. The accelerated corrosion results in metal loss which reduces the mechanical strength of the component.

The refurbishment candidates are based on condition assessments. If no metal loss is visible at the time of assessment, the footings and/or anchors are re-coated to restore the corrosion protection and extend the life of the component(s). If metal loss is visible at the time of assessment, the affected components are scheduled for refurbishment.

Hydro One Transmission's steel structure foundation refurbishment program is focused on assessing, restoring, and refurbishing the grillage foundations to extend the life of the steel that is at and below the ground line. The proposed plan will be to assess, coat and refurbish 700 grillage foundations each year over the test years. This represents an average refurbishment rate of 1.4% of the structures each year and is consistent with the bridge year.

Witness: Chong Kiat (CK) Ng

Alternatives:
Two alternatives were considered:
Alternative 1: Continue to maintain the assets (status quo); or
Alternative 2: Refurbishment of the assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 is the preferred alternative as it maintains reliability and mitigates risk of failure and public safety concerns.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
Maintain system reliability and mitigate public safety concerns by addressing a total of 1400 grillage foundations over the test years and extend the life of steel structure foundations.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	7.9	7.9	15.8
Operations, Maintenance & Administration and Removals	(0.1)	(0.1)	(0.2)
Gross Investment Cost	**7.8**	**7.8**	**15.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**7.8**	**7.8**	**15.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Shieldwire Replacements
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address shieldwire that is in deteriorated condition and at end of life in order to maintain system reliability. Not proceeding with this investment will result in jeopardizing system reliability, increasing the number of customer interruptions, and increasing the risk of safety hazards to employees and the public.

Investment Summary:
Hydro One's transmission system consists of about 35,000 kilometers of overhead shieldwire. Almost all overhead transmission lines have shieldwire strung above the conductor to protect against lightning strikes and provide grounding continuity.

The majority of shieldwires in Hydro One's transmission system is made of galvanized steel wire, whose protective zinc coating deteriorates over time. When the galvanizing corrosion protection has depleted, the underlying steel begins to corrode resulting in loss of metal, reduction in mechanical strength, and eventual failure of the shieldwire. When failure does occur, the broken shieldwire usually makes contact with the conductors before falling to the ground, resulting in a circuit outage. It can also create a safety risk to the public depending on the location of the failure.

The condition of the shieldwire is monitored through an annual shieldwire condition assessment program which selects candidates from line sections throughout the transmission system to assess the remaining tensile strength and overall condition of the wires. Since 2016, Hydro One has implemented a non-destructive condition assessment method for shieldwires which eliminates the need for outages for the assessments. This method is more efficient and cost effective as the costs associated with obtaining outages will be eliminated. Currently, the shieldwire assessment results indicate that approximately 480 km of galvanized shieldwire is at end of life and in high risk of failure in the next few years.

The proposed plan will be to replace about 150 km of shieldwire per year in the test years 2017 and 2018. This represents an average replacement rate of about 0.4% over each test year.

Alternatives:
Two alternatives were considered:
Alternative 1: Continue to maintain the assets (status quo); and
Alternative 2: Replacement of the assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 is the preferred alternative as it addresses the issues with the assets and maintains reliability while mitigating employee and public safety issues.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To maintain reliability and mitigate employee and public safety issues through replacing a total of 300 km of shieldwire over the test years.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	7.9	8.1	16.0
Operations, Maintenance & Administration and Removals	(0.9)	(1.0)	(1.9)
Gross Investment Cost	**7.0**	**7.1**	**14.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**7.0**	**7.1**	**14.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Insulator Replacements
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address polymer insulators, defective porcelain insulators, and other insulator defects in the system, by replacing insulators with the highest risk of failure. Insulator failure can result in public safety concerns and decreased system reliability. Not proceeding with this investment will negatively impact system reliability, causing an increased number of customer interruptions, and more importantly a public safety risk.

Investment Summary:
Hydro One Transmission currently owns and manages about 420,000 insulator strings. Insulators are used to support the current carrying conductors and provide electric isolation to the supporting steel or wood structures. There are three main types of string insulators used on the transmission system: porcelain, glass and polymer. Quality porcelain and glass insulators normally have a life expectancy similar to that of conductors and do not require replacement until the line is completely refurbished. However, polymer and some porcelain and glass insulators require replacement before the conductor reaches end of life due to manufacturing defects, lightning strikes and vandalism.

Insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1965 and 1982 suffer from a phenomena known as cement expansion or cement growth. The purpose of the cement is to bond the pin to the porcelain. Excessive cement expansion of these insulators would create cracks in the cement and porcelain shell resulting in two possible failure modes:

1. Mechanical Failure causing a conductor drop; and
2. Electrical Failure where the cracked porcelain reduces insulating properties.

As a result, some of these insulators will fail prematurely. Factors such as mechanical load and environmental conditions may also influence the cause premature failure. However cracks in the cement and porcelain shell are not always visible or detectable, which along with the number of insulators in the system, make it difficult to predict which insulators will fail. For example, Hydro One recently experienced an insulator failure on its V76R circuit. In March 2015, the centre phase insulator on V76R failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. This type of failure represents a significant public safety risk. As a result, in 2016 Hydro One Transmission implemented an insulator replacement strategy.

There are approximately 34,000 structures with defective COB or CP insulators and roughly 15,000 of these structures have been identified as high risk. High risk structures include structures at road crossings, water and rail crossings and structures near urban areas, golf courses, educational and health care facilities. In 2016, a province wide replacement program for defective COB and CP insulators began. COB and CP insulators on high risk structures will be replaced over the next five years.

The proposed plan will be to replace approximately 4,030 circuit structures and 3,880 circuit structures in 2017 and 2018 respectively.

Alternatives:
Two alternatives were considered:
Alternative 1: Continue program at historical rate (Status Quo); or
Alternative 2: Replacement of the assets.

Alternative 1 was considered and rejected due to the public safety risk and condition of the assets. Alternative 2 is the preferred alternative as it addresses the asset condition, reduces the public safety concern and maintains reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To reduce public safety risks associated with insulator failures and maintain reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	72.6	69.8	142.4
Operations, Maintenance & Administration and Removals	(8.7)	(8.4)	(17.1)
Gross Investment Cost	**63.9**	**61.4**	**125.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**63.9**	**61.4**	**125.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Transmission Lines Emergency Restoration
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To make emergency repairs to the overhead transmission system as they occur, to maintain system reliability. Not proceeding with this investment is typically not an option, since transmission line emergency restoration is required to address public or employee safety hazards, and circuit outages including customer interruptions.

Investment Summary:
Hydro One's transmission system consists of approximately 30,000 circuit kilometers of overhead transmission line, which includes approximately 52,000 steel structures and 42,000 wood structures and associated hardware ranging in age from new to over 100 years old.

An "emergency" is defined as: a structure or component that has "failed" or is at "risk of imminent failure"; where the failure could result in a serious public or employee safety hazard, circuit outage, and/or property damage. The proposed funding for the transmission lines emergency restoration during the test years are based on recent historic levels of spending associated with emergency repairs.

When structures and/or components fail under emergency circumstances it is not usually due to age or condition and, in most cases, the failure could not have been prevented. The reasons for failure include, but are not limited to: normal weather conditions (i.e. lightning), severe weather events (i.e. tornado), motor vehicle accidents, design defects, acts of vandalism. In addition to structures and/or components that have failed, Hydro One Transmission must also respond to structures and/or components that are "at risk of imminent failure" that are identified through condition patrols. An example would be a wooden cross-arm or structure that has been damaged by lightning. It may not have failed but is very close to failing. Such repairs are also considered an emergency.

Alternatives:
This program is in response to emergency outages and no alternatives were considered as failure to respond to service interruptions or other emergency situations would result in unacceptable reliability and safety risks.

Basis for Budget Estimate:
This program cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of programs of similar scope.

Outcome:
To minimize public and employee safety risks, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	9.9	10.0	19.9
Operations, Maintenance & Administration and Removals	(1.2)	(1.2)	(2.4)
Gross Investment Cost	**8.7**	**8.8**	**17.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.7**	**8.8**	**17.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Gordie Howe International Bridge (GHIB) - Recoverable
Target Start Date: Q4 2015
Targeted In-Service Date: Q2 2018
Targeted Outcome: *Customer Focus*

Need:
To meet customer needs for modification of existing transmission assets. Not proceeding with this investment will impede or delay the construction of the GHIB and fail to meet customer needs.

Investment Summary:
The Government of Canada, through the Windsor Detroit Bridge Authority (WDBA) and Transport Canada (TC) (the "Proponents"), is committed to the development of the Gordie Howe International Bridge (GHIB), which is a new international crossing between Windsor and Detroit. WDBA is responsible for the construction and operation of GHIB, while TC is responsible for all real estate matters. The Proponents have requested the modification of several existing transmission and distribution facilities in order to accommodate the GHIB Project.

GHIB will impact facilities connecting to Keith Transformer Station (TS), including transmission assets, distribution assets, and a customer connection. To accommodate the GHIB the following must be modified: station equipment and facilities within Keith TS; transmission circuits J5D (230 kV), C21J/C22J (230 kV), J3E/J4E (115 kV); connection facilities for customer owned circuit J2N (115 kV); and distribution feeders 23M3, 23M4, and 23M5 (27.6 kV). Moreover, the Proponents require part of the existing Keith TS property in order to execute their development. This will require Hydro One to modify access and municipal service connections to the existing station site.

The total cost for this investment is $41 million (which includes a Distribution facilities costs). The costs associated with this investment will be recovered from the Proponents (WDBA and TC) and a connected customer (WWP) with the following exceptions:

1. Hydro One will incur $0.330 million to install two new oil-water separators (OWS) at Keith TS. The total cost for these items is $0.730 million, of which $0.4 million is recoverable from WDBA. Hydro One is covering a portion of this cost as the existing OWS systems at Keith

TS are inadequate, and Hydro One would have upgraded these systems even in the absence of the GHIB development; and

2. The costs for the customer connection modifications will be largely recovered directly from West Windsor Power. The costs for this work total $1.92 million. Hydro One will recover $1.6 million, but will be responsible for the balance of $0.328 million. Hydro One is covering a portion of the cost because the existing breaker protection is at end of life and replacement would be required irrespective of this project.

Part of the investment will modify 230 kV international interconnection circuit J5D and will require National Energy Board (NEB) approval, regardless of who performs the work. Work on the international interconnection circuit (J5D) cannot commence until NEB approval is granted. This project was not included in the 2015/16 Transmission Rates Application (EB-2014-0140). The majority of the work will be recovered from the proponents and connected customer, with the exception of $0.658 million, which will be added to Hydro One Transmission's regulated rate base in the year it is placed in-service. This project does not trigger a requirement for a Section 92 application since it involves line relocation.

Alternatives:
There are no alternatives for this project.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One

Outcome:
To meet customer needs by modifying existing transmission assets for the GHIB development.

Costs:

($ Millions)(Transmission + Distribution)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	13.5	12.8	34.1
Operations, Maintenance & Administration and Removals	(0.8)	(0.3)	(1.1)
Gross Investment Cost	**12.7**	**12.5**	**33.0**
Capital Contribution	(13.3)	(12.4)	(33.7)
Net Investment Cost	**(0.6)**	**0.0**	**(0.7)**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Manvers - Lafarge Aggregate Pit - Recoverable
Targeted Start Date: Q4 2018
Targeted In-Service Date: Q4 2020
Targeted Outcome: *Customer Focus*

Need:
To meet customer needs for modification of existing transmission assets and to maintain system reliability by relocating transmission lines and towers at the request of customer. Not proceeding with this investment would fail to satisfy customer needs and potentially negatively impact system reliability.

Investment Summary:
Four Hydro One owned 230 kV transmission circuits (C28C, H24C, H26C, M29C) cross through Lafarge's Pit #20, which is located north of Mosport International Raceway, on the north side of Boundary Road roughly 3.5k west of Hwy 35. The pit's area covers approximately 500 acres, in five Township lots. The Hydro One lines are approximately 14 circuit km, extending across all five lots and through the operating pit.

Aggregate excavation has, over the years, left several Hydro One towers islanded atop 30 meter high pedestals of land. Approximately 38 transmission structures are affected. Hydro One has provided an estimate to relocate the towers and is waiting for acceptance before proceeding with the project.

The costs associated with this project are 100% recoverable from the proponent.

Alternatives:
There are no alternatives for this project.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One

Outcome:
To meet customer needs and to mitigate reliability risk.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.0	3.8	13.8
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**1.0**	**3.8**	**13.8**
Capital Contribution	(1.0)	(3.8)	(13.8)
Net Investment Cost	**0.0**	**0.0**	**0.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: H7L / H11L Cable Replacement
Targeted Start Date: Q1 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address 115 kV low pressure oil filled underground cables in poor condition, in order to maintain system reliability. Not proceeding with this investment will increase the probability of failures, adversely impacting the supply of electricity to the east end of Toronto.

Investment Summary:
Circuits H7L and H11L provide a critical network path from Portlands Generating Station to Leaside TS and supply to Main TS and the load that these cables serve is critical. These 115 kV circuits consist of two parallel circuits of overhead lines and two sections of underground cables.

This investment is required to address the condition of the 115 kV low pressure oil filled underground transmission cables H7L and H11L between Leaside TS and Main TS. The cables are over 60 years old and are in poor condition. They have deteriorated to the point where they have been assessed as being among the worst condition of the current cable population, with multiple oil leaks, major cable failures, and cable sheath jacket failures. Poor backfill soil thermal resistivity has also resulted in de-rating of the cables that may result in future supply constraints. The oil pressurization systems and terminal accessories are also in poor condition and continue to experience oil leaks.

Equipment to be replaced within this project includes the replacement of the existing 115 kV low pressure oil filled cables with new XLPE cables for a route distance of approximately 2.3 kilometers.

Since the initiation of the project, the targeted in-service date for this project has changed from December of 2016 to November of 2018 due to complexity of required environmental assessments and public consultations. The project is still under development with a targeted in-service date of November 2018.

Alternatives:
Two alternatives were considered:
Alternative 1: Continue to maintain the assets without replacement (Status Quo); or
Alternative 2: Replace the assets.

Alternative 1 was considered and rejected due to the deteriorating asset condition, equipment performance and increased risk of failure. Alternative 2 is the preferred alternative as it addresses the deteriorating asset condition and equipment performance and will maintain reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of project of similar scope.

Outcome:
To maintain reliability through replacing the 115 kV underground transmission cables H7L and H11L.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.3	21.2	24.5
Operations, Maintenance & Administration and Removals	0.0	(0.1)	(0.1)
Gross Investment Cost	**1.3**	**21.1**	**24.4**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**1.3**	**21.1**	**24.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Inter-Area Network Transfer Capability

Investment Name: Clarington TS: Build new 500/230 kV Station
Targeted Start Date: Q1 2014
Targeted In-service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness, Customer Focus*

Need:
To provide additional 500/230kV auto-transformation facilities, and reactive support following the retirement of the Pickering Nuclear Generating Station. There is also a need to improve the 230kV supply security and restoration capabilities to the Pickering, Ajax, Oshawa and Clarington areas. Not proceeding with this investment would result in inadequate supply capacity and security to meet the loads in the east GTA area.

Investment Summary:
The shutdown of Pickering NGS will result in overloading on the Cherrywood TS 500/230kV autotransformers and a significant reduction in reactive support. Pickering NGS currently provides 3000 MW of active power and over 1200 MVar of reactive power to supply and support the east GTA loads. The former OPA[1], in letters dated October 3, 2011 and January 11, 2012, requested Hydro One to initiate work to provide additional 500/230kV auto-transformation capacity in the east GTA. The former OPA further provided supporting evidence in Proceeding EB-2012-0031 outlining the rationale for the need of these facilities and the restoration capabilities.

On January 11, 2016 Ontario Power Generation announced that it plans to work with the Ministry of Energy, the IESO and the OEB to pursue continued operation of Pickering NGS to 2024. OPG has started work on the application to request approval of an amendment to the nuclear power reactor operating license for Pickering NGS from the Canadian Nuclear Safety Commission (“CNSC”).[2]

In a letter dated February 8, 2016, the IESO confirmed the need for completing the Clarington TS project to provide the required levels of supply security and restoration capability by 2018 and also to mitigate a very high impact risk should OPG not receive approval from the CNSC when their current license expires in August 2018.

The proposed plan entails construction of a new 500/230kV station on Hydro One owned lands at the Clarington Junction site. The new station will be equipped with two 750MVA autotransformers, appropriate 500kV and 230kV switching facilities and two 300MVar capacitor

[1] As of January 1, 2015 the Ontario Power Authority (“OPA”) merged with the Independent Electricity System Operator (“IESO”) to create a new organization called the IESO that combines the OPA and IESO mandates.
[2] http://www.opg.com/news-and-media/news-releases/Documents/20160111_DarlingtonRefurb.pdf

banks. The new station will sectionalize and connect the five existing 230kV circuits that emanate from Cherrywood TS.

Hydro One has now obtained all necessary approvals for building the new station and the project is under construction. The project is expected to be complete by October 2018, following the project start delayed to summer 2015 with the last Environmental Assessment approval (Permit to Take Water) being obtained in May 2015.

Alternatives:

Three transmission alternatives were considered by the former OPA to provide increased 230kV capability as outlined in the Description of Need and Rationale documentation provided in Proceeding EB-2012-0031. These alternatives were:

- Alternative 1 – Build a new 500/230kV Station on Hydro One owned land in Clarington
- Alternative 2 – Expand Cherrywood TS by installing additional 500/230kV autotransformers
- Alternative 3 – Expand Parkway TS by installing additional 500/230kV autotransformers

The former OPA concluded that Alternative 1 was the recommended alternative, as it was the only alternative that satisfied all the needs and could be implemented in time.

Basis for Budget Estimate:

The project cost is based on a detailed cost estimate prepared by Hydro One.

Outcome:

To meet supply security and restoration requirements in the east GTA area, to ensure adequate supply when Pickering NGS retires and to mitigate the supply risk should OPG not receive approval to operate Pickering NGS beyond 2018.

Costs:

The project costs will be recovered from the network rate pool as these 500kV and 230kV facilities are network assets and no capital contribution is required from the customer.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	69.1	15.0	281.7
Operations, Maintenance & Administration and Removals	(0.5)	(0.2)	(1.0)
Gross Investment Cost	**68.6**	**14.8**	**280.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**68.6**	**14.8**	**280.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Inter-Area Network Transfer Capability

Investment Name: Nanticoke TS: Connect HVDC Lake Erie Circuit
Targeted Start Date: Q1 2017
Targeted In-service Date: Q4 2019
Targeted Outcome: *Customer Focus*

Need:
To connect the 1000MW HVDC line between Ontario and Pennsylvania, proposed by the ITC Lake Erie Connector LLC ("ITC"), to Hydro One's transmission system at Nanticoke. Hydro One is obligated under its electricity transmission license to connect any customer that requested connection to Hydro One's transmission system. Not proceeding with this investment would be a violation of Hydro One's transmission license.

Investment Summary:
The ITC is planning to build a 117km long, underwater HVDC cable line between converter stations located in Nanticoke, Ontario and Erie, Pennsylvania, USA. Short AC lines will connect the Nanticoke and Erie converter station to the Ontario and Pennsylvania transmission systems.

This project entails the installation of necessary switching facilities at Hydro One's Nanticoke TS 500kV switchyard in order to terminate the ITC 500kV AC line from the Nanticoke Converter Station.

ITC has applied to the National Energy Board in Canada and the US Department of Energy for necessary project approvals and expect these approvals by 2017. The project is expected to be completed by October 2019.

Alternatives:
No alternatives to connection were considered, as failure to connect would place Hydro One in violation of its electricity transmission license.

Basis for Budget Estimate:
Hydro One is in the process of estimating two approaches of terminating the new 500kV circuits:
(a) Extend the 500kV switchyard and add two 500 kV breakers to connect the new circuit; or
(b) Utilize an existing idle position (as a result of the Nanticoke generators retirement) and replace two existing breakers to connect the new circuit.

For the purposes of this rate application, the project cost is based on a budgetary estimate prepared by Hydro One, for the approach (a) that entails the extension of the 500kV switchyard. A decision on the preferred approach will be made by year end 2016.

Outcome:
To connect the ITC HVDC line to the Ontario transmission system.

Costs:
The project costs will be recoverable through capital contributions from the customer. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.0	13.0	36.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**5.0**	**13.0**	**36.0**
Capital Contribution	(5.0)	(13.0)	(36.0)
Net Investment Cost	**0.0**	**0.0**	**0.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Inter-Area Network Transfer Capability

Investment Name: Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade
Targeted Start Date: Q3 2017
Targeted In-service Date: Q1 2020
Targeted Outcome: *Operating Effectiveness*

Need:
To increase the loading capability of the 230kV double circuit line (M30A/M31A) between Hawthorne TS and Merivale TS to facilitate firm import capacity from Quebec. Not proceeding with this investment would result in not complying with the requirements of the Memorandum of Understanding on the Seasonal Capacity Exchange agreement reached between the Provinces of Ontario and Quebec.

Investment Summary:
The Provinces of Ontario and Québec have signed a Memorandum of Understanding to exchange electricity capacity. Under this Seasonal Capacity Exchange agreement, Ontario will provide 500MW of available electricity capacity to Quebec in winter, and Quebec will provide 500MW of available electricity capacity to Ontario during the summer. The agreement is beneficial to both provinces as it assists Ontario reduce the need and associated costs of building future electricity generating stations, and provides Québec with additional capacity to meet its seasonal needs.

The circuits M30A/M31A are the only 230kV lines connecting Hawthorne TS and Merivale TS in Ottawa. In addition to power transfer between the two stations, these circuits also supply two load stations, Albion TS and Ellwood TS.

By the summer of 2020, the flow on the circuits M30A/M31A is forecast to exceed the loading capability of the circuits during peak load conditions and with 500MW imports from Quebec. The IESO has determined that the circuits M30A/M31A need to be upgraded to handle the forecast transfers.

This project entails the replacement of the existing conductors with new higher rated conductors. Hydro One will be proceeding with a "Leave to Construct" application under Section 92 of the *Ontario Energy Board Act* in 2016 to seek the Ontario Energy Board approval for the project. The project is expected to be completed by February 2020.

Alternatives:
For the purposes of this rate application, two alternatives were considered, but are conditional on the Section 92 "Leave to Construct" application. These alternatives are:

- Alternative 1 – Build new 230kV lines between the two stations; or
- Alternative 2 – Replace existing 230kV line with higher capacity conductor.

Both alternatives meet the needs of the system; however Alternative 2 is the preferred and recommended alternative as it is the least cost alternative. Alternative 1 would require installing new towers and lines that would be extremely costly and environmentally impactive.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To increase the loading capability of the circuits between Hawthorne TS and Merivale TS to satisfy the requirements of the Seasonal Capacity Exchange Agreement between Ontario and Quebec.

Costs:
The project costs will be recovered from the network rate pool as these 230kV circuits are network assets and no capital contribution is required from the customer.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	2.5	8.0	20.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**2.5**	**8.0**	**20.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**2.5**	**8.0**	**20.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Inter-Area Network Transfer Capability

Investment Name: East-West Tie Expansion: Station Work
Targeted Start Date: Q3 2017
Targeted In-service Date: Q4 2020
Targeted Outcome: *Public Policy Responsiveness*

Need:
To connect the proposed 230 kV double circuit East-West Tie between Wawa and Thunder Bay. Not proceeding with this investment would be a violation of Hydro One's transmission license.

Investment Summary:
The Ontario Government's Long Term Energy Plan ("LTEP") of November 2010 identified the need to reinforce the East-West Tie, an electricity transmission line running between Wawa and Thunder Bay, as a priority transmission project. This project is required to maintain an acceptable standard of reliability in the region amidst load growth in the mining sector in the northwest coupled with the change in the regions supply mix (including the shutdown and conversion of coal-fueled power plants at Thunder Bay and Atikokan).

Subsequent to the LTEP, the Ontario Energy Board designated Upper Canada Transmission ("NextBridge") to undertake the development of the East-West Tie ("EWT") Project which is a 445km long 230kV double-circuit overhead line between Hydro One's Wawa TS and Lakehead TS near Thunder Bay with a connection approximately mid-way at Marathon TS. The EWT Project is anticipated to increase the transfer capability between the Northeast and Northwest regions of Ontario to 650MW, thereby improving the long-term reliability of the electricity supply to northwestern Ontario while satisfying the increasing demand from the mining sector, including developments at the Ring of Fire, connection of the remote communities, and the proposed pipeline conversion project.

This project entails the construction of necessary switching facilities to connect the new line at Wawa TS, Marathon TS and Lakehead TS; which includes switchgear, shunt reactors, capacitor banks and static Var compensators, as initially identified by the IESO Feasibility Study[1] for the Ontario Energy Board. The original in-service date was planned for 2018; however based on the outlook for new mine developments and growing demand, the IESO requested the Ontario Energy Board to allow the in-service date to be deferred. This request was approved by the Ontario Energy Board in its Decision in Proceeding EB-2015-0216 dated November 19, 2015.

[1] http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/EWT_IESO_Feasibility_Study_Final_20110818.pdf

The IESO has recommended staging the project to meet the expected need for 650 MW transfer capability at a later date. Consequently, the original scope of work has been revised and this investment provides the connection of the new lines and only the station facilities to meet the 450MW transfer level by 2020. The installation of the static Var compensator and associated station modifications to meet the 650MW transfer level has been postponed to a later stage.

The Ministry of Energy, in a letter dated March 10, 2016, informed the Ontario Energy Board that under the authority of section 96.1 (1) of the *Ontario Energy Board Act, 1998*, the Lieutenant Governor in Council made an order declaring that the construction of the East-West Tie transmission line is needed as a priority project.

Nextbridge will be required to apply for "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act* for construction of the 230 kV line. Hydro One will be required to apply for "Leave to Construct" approval for the station facilities and connection of the line at the stations.

Alternatives:
No alternatives to connection were considered, as failure to connect would place Hydro One in violation of its electricity transmission license.

Basis for Budget Estimate:
The project cost is based on the budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased supply reliability for customers in Northwestern Ontario.

Costs:
The project cost will be recovered from the network rate pool as these 230kV facilities are network assets and no capital contribution is required from customers.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	3.0	30.0	166.1
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**3.0**	**30.0**	**166.1**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.0**	**30.0**	**166.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization

Hydro One Networks – Investment Summary Document

Development Capital - Inter-Area Network Transfer Capability

Investment Name: Milton SS: Station Expansion and Connect 230 kV Circuits
Targeted Start Date: Q2 2019
Targeted In-service Date: Q2 2022
Targeted Outcome: *Operational Effectiveness*

Need:
To increase transfer capability and improve supply security in the West GTA region, as documented in the Northwest GTA Integrated Regional Resource plan[1]. Not proceeding with this investment would limit transfer capability and would result in inadequate capacity to supply the west GTA loads.

Investment Summary:
The IESO bulk system studies have indicated that the loading on 500/230kV autotransformers at Trafalgar TS along with the loading on the 230kV circuits (R14T, R17T, R19T and R21T) between Richview TS and Trafalgar TS are forecast to exceed their capability as early as 2022. The two primary factors driving the overloads are: (a) load growth in the GTA, specifically in the West GTA; and (b) increased inter-area flows due to the scheduled refurbishment of nuclear units at Bruce GS and Darlington GS along with the planned retirement of Pickering GS.

The Northwest GTA Integrated Regional Resource plan has also identified that loads connected to the Burlington TS to Trafalgar 230kV circuits (T38B/T39B) are at risk of not meeting the restoration criteria as defined in the IESO's Ontario Resource and Transmission Assessment Criteria[2].

In order to address these risks, the IESO is recommending to add 500/230kV transformation facilities at Milton TS and reconfigure the 230kV facilities in Northwest GTA. The project would entail:

- Installation of two 500/230kV autotransformers at Milton SS;
- Construction of a new 230kV switchyard at Milton SS; and
- Construction of an approximately 12.5 km 230kV double circuit line to connect the new Milton TS to Hurontario TS using the existing right of way.

The new facilities will provide relief for the loading on autotransformers at Trafalgar TS and the 230kV circuits between Richview TS and Trafalgar TS. The reconfiguration will also allow the T38B/T39B circuits loading to comply with the IESO Restoration criteria.

[1] http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf
[2] http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

Witness: Bing Young

Hydro One will be required to apply for "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act*, and Class EA approval under the *Environmental Assessment Act*. The project is expected to be completed by June 2022.

Alternatives:
Two transmission alternatives were considered by the IESO to address the needs in the West GTA region. These alternatives are:

- Alternative 1 – Install two new autotransformers, construct a new 230kV switchyard at Milton SS, and construct approximately 12.5km of double circuit 230kV line between Milton SS and Hurontario SS; or
- Alternative 2 – Install two new autotransformers, expand the 230kV switchyard at Trafalgar TS, and construct approximately 8km of double circuit 230kV line between Meadowvale TS and Hurontario SS.

The IESO concluded based on preliminary studies that Alternative 1 is the preferred alternative as it is the least cost alternative and provides greater operating flexibility.

Basis for Budget Estimate:
The project cost is based on budgetary costs estimates prepared by Hydro One.

Outcome:
To provide adequate supply to West GTA region and maintain system reliability.

Costs:
The project costs will be recovered from the network rate pool as these 230kV facilities are network assets and no capital contribution is required from the customer.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	2.0	5.0	250.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**2.0**	**5.0**	**250.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**2.0**	**5.0**	**250.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Local Area Supply Adequacy

Investment Name: Galt Junction: Install In-Line Switches on the M20D/M21D Circuits
Targeted Start Date: Q1 2016
Targeted In-service Date: Q2 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To improve the load restoration capability for the loads supplied from the 230 kV circuits (M20D/M21D) following major outages, as documented in the Kitchener, Waterloo, Cambridge and Guelph ("KWCG") Regional Infrastructure Plan. Not proceeding with this investment would result in Hydro One not being able to meet the IESO's restoration criteria.

Investment Summary:
The 230 kV double-circuit line (M20D/M21D) from Middleport TS to Detweiler TS and Preston TS supplies six step down transformer stations in the KWCG region, specifically three stations supplying Cambridge Hydro, two stations supplying Kitchener-Wilmot Hydro and one industrial customer station. The existing transmission infrastructure does not meet the restoration criteria, as defined in the IESO's Ontario Resource and Transmission Assessment Criteria[1], in the event of a major outage involving the loss of both transmission circuits. The KWCG Regional Infrastructure Plan has identified the need to improve restoration capability to the load stations connected to 230kV circuits (M20D/M21D).

This project entails the installation of two 230 kV in-line load interrupter switches on circuits M20D/M21D. The switches will provide operational flexibility to sectionalize the transmission circuits in order to quickly restore supply to customers following a double circuit contingency. This project also provides greater operational flexibility for planned outages. The project is expected to be completed by June 2017.

Alternatives:
Two alternatives were considered to improve restoration capability as follows:

- Alternative 1 – Install two 230kV in-line load interrupter switches at Galt Junction; or
- Alternative 2 – Install a second 230/115kV autotransformer at Preston TS and install two 230kV in-line load interrupter switches at Preston Junction.

[1] http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

The alternatives were compared based on the cost and the amount of load restored. Alternative 1 was the preferred and recommended alternative as it allows the greatest amount of load to be restored at the least cost.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To improve restoration capability for the loads supplied by the 230 kV circuits (M20D/M21D) in the KWCG area.

Costs:
The project cost will be recovered from the network rate pool as these switches on the 230kV circuits are network assets and no capital contribution is required from customers.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	3.6	0.1	4.5
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**3.6**	**0.1**	**4.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.6**	**0.1**	**4.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Local Area Supply Adequacy

Investment Name: York Region: Increase Transmission Capability for B82V/B83V Circuits
Targeted Start Date: Q4 2015
Targeted In-service Date: Q4 2017
Targeted Outcome: *Customer Focus*

Need:
To increase loading capability of the 230kV double circuit line (B82V/B83V) between Claireville TS and Brown Hill TS to meet forecast load growth in Northern Vaughan and York Region, and to improve restoration capability following major outages, as documented in the GTA North Regional Infrastructure Plan. Not proceeding with this investment would result in an increased risk of customer interruptions affecting supply reliability to customers and the inability to support customer load growth.

Investment Summary:
The 230kV double circuit line (B82V/B83V) supplies loads in Northern Vaughan and York Region through three Hydro One owned step-down transformer stations — Holland TS, Armitage TS and Brown Hill TS. The 393MW York Energy Center generating station is also connected to this transmission line close to Holland TS.

Following a joint regional planning study for the area, as part of the York Region Integrated Regional Resource Plan, the former OPA[1] in its letter[2] dated June 14, 2013, requested Hydro One develop and implement the near-term transmission wires solution component of the integrated plan to improve the loading capability of the B82V/B83V transmission line and improve restoration capability following major outages. The GTA North Regional Integrated Plan confirmed the need for this project.

This project entails:
- Installation of two in-line breakers and six motorized disconnect switches on the B82V/B83V circuits at Holland TS; and
- Implementation of a Load and Generation Rejection scheme for the stations connected to the B82V/B83V circuits.

These measures will increase the loading capability of the circuits from 540MW to about 750MW to support customer load growth in Northern Vaughan and York Region. It will also

[1] As of January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization called the IESO that combines the OPA and IESO mandates.
[2] http://www.ieso.ca/Documents/Regional-Planning/GTA_North/OPA-Letter-Hydro-One-York-Subregion.pdf

allow restoration of customer loads utilizing the York Energy Centre as a local supply source, following a major outage on the main transmission line. The project is expected to be completed by October 2017.

Alternatives:
No alternatives were considered in the Integrated Regional Resource plan for the York Region. The installation of in-line breakers and the load and generation rejection scheme were the only practical alternative to meet the need. Furthermore, the proposed configuration was selected to allow the new infrastructure to be sited on Hydro One's existing property, thus avoiding the need to establish new right-of-ways or obtain additional land.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To improve load supply and restoration capability for customers in Northern Vaughan and York Region.

Costs:
The project cost will be recovered from the network rate pool as these 230kV circuits are network assets and no capital contribution is required from customers.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	22.6	0.2	31.8
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**22.6**	**0.2**	**31.8**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**22.6**	**0.2**	**31.8**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Local Area Supply Adequacy

Investment Name: Hawthorne TS: Autotransformer Upgrades
Targeted Start Date: Q3 2016
Targeted In-service Date: Q2 2018
Targeted Outcome: *Customer Focus*

Need:
To increase transformation capacity to accommodate the forecast customer load growth in the Ottawa 115kV area, as documented in the Greater Ottawa Area Regional Infrastructure Plan. Not proceeding with this investment would result in increased risk of customer interruptions affecting supply reliability to customers and the inability to supply customer demand in the area.

Investment Summary:
Hawthorne TS is a major supply point for the city of Ottawa. The Ottawa Area 115kV system is supplied from six 230/115kV autotransformers, four at Hawthorne TS and two at Merivale TS. While most of the autotransformers are rated at 250 MVA with a limited time rating of over 300MVA, two of the Hawthorne TS autotransformers (T5 and T6) have a lower rating of 225MVA and a limited time rating of 256MVA. These two autotransformers are 55 and 56 years old respectively, and have exceeded the transformers expected service life of 50 years.

The Greater Ottawa Area Regional Infrastructure Plan has identified that the load meeting capability for the Ottawa Area 115kV system is limited due to the capability of these two lower capacity autotransformers.

This project entails the replacement of the two existing Hawthorne autotransformers (T5 and T6) with new higher capacity 250MVA autotransformers in order to accommodate the customer load demand. The project is expected to be completed by June 2018.

Alternatives:
No alternatives were considered. The Greater Ottawa Working Group recommended replacement of the two Hawthorne TS autotransformers given the age of the transformers, along with the immediate timing of the need. Replacement of these autotransformers was deemed the simplest and lowest cost approach to meet the transformation capacity need.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Witness: Bing Young

Outcome:
To improve supply capability and reliability for customers in the Greater Ottawa area.

Costs:
The project cost will be recovered from the network rate pool as these autotransformers are network assets and no capital contribution is required from customers.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	8.0	5.8	16.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**8.0**	**5.8**	**16.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.0**	**5.8**	**16.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Local Area Supply Adequacy

Investment Name: Brant TS: Install 115kV Switching Facilities
Targeted Start Date: Q1 2017
Targeted In-service Date: Q1 2019
Targeted Outcome: *Customer Focus*

Need:
To increase loading capability of the 115kV double circuit line (B12/B13) between Burlington TS and Brant TS to meet forecast load growth in Brant Area, as documented in the Brant Area Integrated Regional Resource Plan. Not proceeding with this investment would result in an increased risk of customer interruptions affecting supply reliability to customers and the inability to supply customer load growth.

Investment Summary:
The 115kV double circuit line (B12/B13) supplies loads in the Brant Area through two step-down transformer stations – Brant TS and Powerline MTS. The combined loads at Brant TS and Powerline MTS exceed the capability of the existing 115kV double circuit line (B12/B13).

The Integrated Regional Resource plan for the Brant Area identified that additional transmission line supply capacity is required to meet the existing and increased future load demand at Brant TS and Powerline MTS.

This project entails construction of a new switchyard at Brant TS station with three new 115kV breakers, and the connection of the B12/B13 and B8W circuits into the new switchyard.

These measures will reinforce the supply to Brant TS and Powerline MTS by integrating the backup supply circuit B8W from Karn TS as a third supply with the existing two circuits (B12/B13) from Burlington TS. This would increase the area load supply capability from 125MW to 165MW. The project is expected to be completed by March 2019.

Alternatives:
Four alternatives were considered in the Integrated Regional Resource plan. These alternatives were:

- Alternative 1 – Implement conservation and demand management initiatives;
- Alternative 2 – Install new local generation;
- Alternative 3 – Perform distribution load transfers; or
- Alternative 4 – Construct a new 115kV switchyard to connect the B12/B13 and B8W circuits.

Witness: Bing Young

Alternatives 1 and 3 were not considered feasible and Alternative 2 was extremely costly. Therefore, the Brant Working Group concluded that Alternative 4 was the preferred and recommended alternative as it meets the need at the least cost.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased supply reliability for the customers supplied by Brant TS and Powerline MTS and support future load growth.

Costs:
The project cost will be recoverable through capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.0	6.0	12.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**5.0**	**6.0**	**12.0**
Capital Contribution	(5.0)	(6.0)	(12.0)
Net Investment Cost	**0.0**	**0.0**	**0.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Local Area Supply Adequacy

Investment Name: Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits
Targeted Start Date: Q2 2017
Targeted In-service Date: Q2 2019
Targeted Outcome: *Customer Focus*

Need:
To increase loading supply capability of the downtown Ottawa 115 kV network to relieve overloading on the 115 kV circuit (A4K) between Hawthorne TS and Overbrooke TS and meet future load growth in the area, as documented in the Greater Ottawa Area Regional Infrastructure Plan. Not proceeding with this investment would result in an increased risk of customer interruptions affecting supply reliability to customers and the inability to supply customer load growth.

Investment Summary:
The Overbrook and Vanier Areas of Ottawa are supplied by two 115kV step-down transformer stations - Overbrook TS and King Edward TS. These two stations are supplied from the 115kV circuits A4K and A5RK. The 115kV circuit A4K also supplies Hydro Ottawa's stations Cyrville MTS and Moulton MTS. With Hydro Ottawa's forecast load growth for the area, it is expected that A4K will exceed its capacity rating for the loss of circuit A5RK.

Following a joint regional planning study for the area, the former OPA[1] in its letter[2] dated June 27, 2013, requested Hydro One to proceed with work to improve the capability of the Ottawa 115kV network to relieve overloading of the A4K circuit. The Greater Ottawa Area Regional Infrastructure Plan confirmed the need for this project.

This project entails:
- Construction of a tap on the 115kV circuit A6R at Riverdale JCT;
- Rebuild approximately 2 km of the existing A5RK tap from Riverdale JCT to Overbrook TS as a 115kV double circuit line; and
- Extension of the A6R circuit to Overbrook TS using the second circuit on the rebuilt line.

This reconfiguration will eliminate the overloading by removing Overbrook TS load from circuit A4K transfer it to circuits A5RK and A6R. The project is expected to be completed by June 2019.

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[1] As of January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization called the IESO that combines the OPA and IESO mandates.
[2] http://www.ieso.ca/Documents/Regional-Planning/Greater_Ottawa/Letter-to-H1-Ottawa.pdf

Alternatives:
Two alternatives were considered to provide the additional supply capacity. These alternatives were:

- Alternative 1 – Upgrade 115kV circuit A4K; or
- Alternative 2 – Reconfigure the 115kV circuits A6R and A5RK.

Due to the ampacity rating of the existing main section of A4K, Alternative 1 would not provide significant incremental supply capacity to the area. As a result, the Greater Ottawa Working Group concluded that Alternative 2 was the preferred and recommended alternative and did not pursue the option of upgrading A4K further.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased supply reliability for the customers in the downtown Ottawa area and support future load growth.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	2.4	4.2	8.7
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**2.4**	**4.2**	**8.7**
Capital Contribution	(1.2)	(2.1)	(4.3)
Net Investment Cost	**1.2**	**2.1**	**4.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Local Area Supply Adequacy

Investment Name: Southwest GTA Transmission Reinforcement
Targeted Start Date: Q1 2018
Targeted In-service Date: Q2 2020
Targeted Outcome: *Customer Focus*

Need:
To increase transfer capability on the 230kV transmission corridor between Richview TS and Manby TS to meet future load growth in the Central Toronto and Southern Mississauga/Oakville areas, as documented in the Metro Toronto Regional Infrastructure Plan. Not proceeding with this investment would result in an increased risk of customer interruptions affecting supply reliability to customers and the inability to supply customer load growth.

Investment Summary:
The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the western sector of Central Toronto region. It also supplies the load to the southern Mississauga and Oakville areas via Manby TS. The Metro Toronto area Regional Infrastructure Plan has identified the need to increase the transfer capability between Richview TS and Manby TS.

This project entails:
- Reconductoring 6.5km of an existing idle 115 kV double-circuit line to 230kV along the same corridor as an existing 230kV double-circuit line;
- Termination of the new 230kV double-circuit line (either using the existing terminations for circuits R2K and R15K or new terminations points); and
- Construction of 230kV towers to replace the existing 115kV towers.

This reconfiguration will relieve the transmission capacity constraint on the existing 230kV corridor between Richview TS and Manby TS. Hydro One will be required to apply for “Leave to Construct” approval under Section 92 of the *Ontario Energy Board Act*, and Class EA approval under the *Environmental Assessment Act*. The project is expected to be completed by May 2020.

Alternatives:
Four alternatives were considered to provide additional capacity. These alternatives were:

- Alternative 1 – Upgrade the existing Richview TS to Manby TS 230kV circuits;
- Alternative 2 – Rebuild the existing idle 115kV line as a 230kV line and connect in parallel with existing Richview TS to Manby TS 230kV circuits;

- Alternative 3 - Rebuild the existing idle 115kV line as a 230kV line and connect using new terminations at Richview TS and Manby TS; or
- Alternative 4 - Extend the existing 230kV line between Cooksville TS and Oakville TS to Trafalgar TS.

The Metro Toronto Working Group has recommended that Hydro One proceed with development work on Alternatives 1 through 3 and a final decision on the preferred alternative to be made by December 2016. Alternative 4 is not being considered because of higher costs. For purposes of this rate application, the project description and associated costs are based on Alternative 3.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased supply reliability for the customers in Central Toronto and Southern Mississauga/Oakville areas and support future load growth.

Costs:
The project cost will be recovered from the network rate pool as these 230kV circuits are network assets and no capital contribution is required from customers.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	0.9	5.0	30.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**0.9**	**5.0**	**30.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**0.9**	**5.0**	**30.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Local Area Supply Adequacy

Investment Name: Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits
Targeted Start Date: Q3 2018
Targeted In-service Date: Q4 2020
Targeted Outcome: *Customer Focus*

Need:
To increase load supply capacity to accommodate the forecast customer load growth in the city of Barrie and Town of Innisfil as well as address end of life equipment issues. Not proceeding with this investment would result in an increased risk of customer interruptions affecting supply reliability to customers and the inability to supply customer demand in the area.

Investment Summary:
Barrie TS is a 115/44kV transformer station presently supplied from 115kV double circuit line (E3B/E4B) originating from Essa TS via 230/115kV autotransformers (T1/T2). With the forecasted load growth in the Barrie/Innisfil area, it is expected that loading will exceed the station capacity by summer 2017 and additional transformation capacity will be required.

Both Barrie TS and the 115kV facilities supplying it are reaching end of life and are in need of replacement. The Barrie TS 115/44kV power transformers and associated 44kV switchyard facilities are over 50 years old. The 115kV facilities at Essa including the transformers and the 115kV switchyard are 65 years old and the 115kV circuit (E3B/E4B) is over 50 years old. The condition of all of these assets is indicating the need for replacement.

The Integrated Regional Resource Planning process is currently in progress for the Barrie/Innisfil area. At the recommendation of the Barrie/Innisfil Working Group, the IESO in its letter dated December 7, 2015, requested Hydro One to proceed with work to improve the load supply capability of the area and address end of life station and line facilities.

This project entails:
- Rebuild Barrie TS switchyard and 115kV transmission line (E3B/E4B) as 230kV facilities;
- Upgrade Barrie TS transformers (T1/T2) from 55/92MVA units to 75/125MVA units; and
- Decommission two 230/115kV autotransformers and associated 115kV switchyard at Essa as the 115kV voltage supply will no longer be needed in the area.

These measures will address end of life station and line facilities and will increase the loading capability to support future customer load growth in the Barrie/Innisfil area.

Hydro One will be required to apply for "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act*, and Class EA approvals under the *Environmental Assessment Act*. The project is expected to be completed by November 2020.

Alternatives:
Two alternatives were considered to provide additional supply capacity. These alternatives were:

- Alternative 1 – Refurbish/replace existing facilities with new 115kV facilities; or
- Alternative 2 – Replace existing 115kV facilities with new 230kV facilities.

Alternative 2 is the recommended alternative as it is the least cost alternative and provides adequate capacity to supply future loads.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To improve the supply capacity and reliability for customers in the Barrie/Innisfil area, while addressing end of life issues with existing Hydro One assets.

Costs:
The project cost will be recovered from the connection rate pools. The overall project cost is expected to be less than the cost for like-for-like replacement of end of life facilities; no capital contribution is expected from customers.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	4.0	20.0	80.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**4.0**	**20.0**	**80.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.0**	**20.0**	**80.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D
Targeted Start Date: Q1 2015
Targeted In-service Date: Q1 2018
Targeted Outcome: *Customer Focus*

Need:
To increase the loading capability of the 115 kV circuit (E4D) between Dryden TS and Ears Falls TS to accommodate new load demand requested by the customers in the Red Lake area, as documented in the North of Dryden Integrated Regional Resource Plan. Not proceeding with this investment will not meet Hydro One obligations under the Transmission System Code to respond to customer capacity requests.

Investment Summary:
The Red Lake area is supplied from Dryden TS by 115kV circuits E4D and E2R. There is load growth anticipated in the area resulting from a number of new mining loads that will be requesting connection between 2015 and 2028. The existing transfer capacity to the area is 84MW and needs to be increased to 105MW to accommodate customers load growth, and enable the load to be served reliably.

The project entails:
- Improvement of the transmission line clearances in a number of locations along the 115kV circuit (E4D) to increase the thermal rating of the circuit;
- Installation of capacitor banks at Red Lake and Ear Falls TS; and
- Implementation of a special protection scheme at Dryden TS.

These measures will allow higher power flows while ensuring adequate voltage performance at those higher levels as well as provide operational flexibility. The planned project in-service date is March 2018.

Alternatives:
Two alternatives were considered to provide additional capacity. These alternatives were:

- Alternative 1 – Upgrade the 115kV circuit between Dryden TS and Ear Falls TS; or
- Alternative 2 – Build new 115kV circuit between Dryden TS and Ear Falls TS (approximately 100km in length).

Alternative 1 was the recommended alternative as it is the significantly lower cost alternative.

Witness: Bing Young

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To provide increased load supply capability to meet customer load growth in the Red Lake area.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.0	5.9	17.5
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**10.0**	**5.9**	**17.5**
Capital Contribution	(8.0)	(4.7)	(14.0)
Net Investment Cost	**2.0**	**1.2**	**3.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Supply to Essex County Transmission Reinforcement
Targeted Start Date: Q4 2015
Targeted In-service Date: Q2 2018
Targeted Outcome: *Customer Focus*

Need:
To increase transformation capacity to accommodate the forecast customer load growth and to improve reliability in the Windsor – Essex region, as documented in the Windsor – Essex Regional Infrastructure Plan. Not proceeding with this investment would result in further degradation of load supply reliability in the region.

Investment Summary:
The Windsor – Essex region is a regional load centre in Ontario with a current load of about 800MW and is forecasted to grow at an annual rate of about 1% over the next 20 years. The area of the largest growth rate is projected to be in the Kingsville – Leamington area where the growth is expected to be largely driven by the greenhouse sector and anticipated growth from new operations.

Studies by the IESO concluded that existing facilities cannot meet the forecast load requirements in the Kingsville – Leamington area, and cannot meet the service interruption requirements for the loads supplied from the 115kV system in the broader Windsor – Essex region following a major transmission outage. Further, Kingsville TS load currently exceeds the capacity of the supply line.

This project entails:
- Construction of a new 230/27.6kV, 75/100/125 MVA transformer station named Leamington TS in the municipality of Leamington; and
- Construction of a 13 km 230 kV double-circuit line on a new right-of-way between the new station and new taps on 230 kV circuits C21J and C22J between Chatham TS and Sandwich Junction at a location about 20 km from Sandwich Junction.

Hydro One has obtained all necessary approvals for this project: the EA approval from the Ministry of the Environment and the Section 92 “Leave to Construct” approval from the Ontario Energy Board in Proceeding EB-2013-0421. The project is under construction and is expected to be completed by June 2018.

Witness: Bing Young

Alternatives:
Two alternatives were considered in the Section 92 "Leave to Construct" application[1] for providing additional capacity. These alternatives were:

- Alternative 1 – Build a new autotransformer station to reinforce the 115kV supply; or
- Alternative 2 – Build a new step-down transformer station to reduce the load in the 115kV system.

As described in the Section 92 application, Alternative 2 was recommended as it is the least cost alternative.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To improve the supply capacity and reliability for customers in the Windsor – Essex region.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions will be determined by the Ontario Energy Board following its policy review of the cost allocation methodology to ensure the cost responsibility between Hydro One Distribution, embedded LDCs and large customers are aligned and facilitate regional planning.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	33.0	31.4	72.3
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**33.0**	**31.4**	**72.3**
Capital Contribution	(11.0)	(10.0)	(21.0)
Net Investment Cost	**22.0**	**21.4**	**51.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

[1] Proceeding EB-2013-0421, Exhibit B, Tab 1, Schedule 5 entitled "OPA Evidence on Needs and Alternatives"

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Horner TS: Build 230/27.6 kV Transformer Station
Targeted Start Date: Q3 2016
Targeted In-service Date: Q2 2018
Targeted Outcome: *Customer Focus*

Need:
To increase the transformation capacity to accommodate the forecast customer load growth in the southwest Toronto area; as documented in the Metro Toronto Regional Infrastructure Plan. Not proceeding with this investment would result in inadequate transmission capacity to supply customer demand in the area.

Investment Summary:
Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load in the southwest end of Toronto. The combined station capacity of 400MW is forecast to be exceeded by summer 2020. The Metro Toronto Regional Infrastructure Plan has identified the need for additional step-down transformation capacity in the area to meet forecasted load growth.

The project entails the construction of a new 230/27.6kV transformer station with two 75/125MVA transformers at the existing Horner TS site. The new transformer station will be supplied by the existing 230kV transmission circuits R2K/R13K which run between Manby TS and Richview TS.

This work will increase the existing capacity the capacity at Horner TS by 170MVA. The project is expected to be completed by June 2018.

Alternatives:
Three alternatives were considered for providing additional capacity. These alternatives were:

- Alternative 1 – Transfer loads to adjacent area stations;
- Alternative 2 – Build a new transformer station at an unknown alternative side; or
- Alternative 3 – Build a second transformer station at the existing Horner TS site.

Both Alternative 2 and 3 would meet the needs of the area; however, Alternative 3 is the recommended alternative as it provides the needed capacity at the lowest costs. Alternative 2 would be extremely expensive due to the difficulties in acquiring and developing a new station site in the area. Alternative 1 was not considered further as the other area stations are at or near capacity limits.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased transformation capacity to supply load growth in the southwest Toronto area.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	16.0	13.0	32.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**16.0**	**13.0**	**32.0**
Capital Contribution	(13.5)	(10.9)	(26.9)
Net Investment Cost	**2.5**	**2.1**	**5.1**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Lisgar TS: Transformer Upgrades
Targeted Start Date: Q2 2016
Targeted In-service Date: Q2 2018
Targeted Outcome: *Customer Focus*

Need:
To increase the transformation capacity to accommodate the forecast customer load growth in the downtown Ottawa area, as documented in the Greater Ottawa Area Regional Infrastructure Plan. Not proceeding with this investment would result in inadequate transmission capacity to supply customer demand in the area.

Investment Summary:
Lisgar TS is a major supply point for Hydro Ottawa customer loads in the downtown Ottawa area. The station loading is forecast to exceed its capacity by summer 2018. The existing facilities at the station consist of two 45/75MVA step-down transformers T1 and T2. Transformer T1 is 42 years olds and is approaching its expected service life. Transformer T2 was installed is five years old and is in good condition. The Greater Ottawa Area Regional Infrastructure Plan has identified the need to provide additional capacity to meet forecasted load growth.

This project entails the replacement of the Lisgar TS transformers T1 and T2 with new step-down 60/100 MVA transformers and associated low voltage connection cables. The existing Transformer T1 will be retired, whereas the newer Transformer T2 will be retained for use as a future spare.

This work will increase the existing station summer 10-day Limited Time Rating from 83MVA to 115MVA. It also has the benefit of providing an increase in connection capacity for renewable generation. The project is expected to be completed by June 2018.

Alternatives:
Three alternatives were considered for providing additional capacity. These alternatives were:

- Alternative 1 – Transfer loads to adjacent area stations;
- Alternative 2 – Build new transformer station at an unknown alternative site; or
- Alternative 3 – Upgrade existing transformers with higher capacity units.

Both Alternative 2 and 3 meet the needs of the area; however, Alternative 3 is the recommended and preferred alternative as it provides the needed capacity at the lowest cost. Alternative 2 would be extremely expensive and challenging to find a new site in the downtown area and Alternative 1 was not considered feasible as the other area stations are at or near capacity limits.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To provide increased transformation capacity to supply load growth in the downtown Ottawa area.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.3	2.5	13.9
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**10.3**	**2.5**	**13.9**
Capital Contribution	(2.8)	0.0	(3.9)
Net Investment Cost	**7.5**	**2.5**	**10.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Seaton MTS: Provide 230 kV Line Connection
Targeted Start Date: Q2 2017
Targeted In-service Date: Q2 2018
Targeted Outcome: *Customer Focus*

Need:
To provide connection to Veridian Connections Inc. ("Veridian") proposed Seaton Municipal Transformer Station ("MTS"). Hydro One is obligated under its electricity transmission license to make connections when requested by customers. Not proceeding with this investment would be a violation of Hydro One's transmission license.

Investment Summary:
Veridian requires new 27.6kV supply capacity for the community of Seaton in northern Pickering. Veridian is planning to build a new 230/27.6kV transformer station - Seaton MTS and has requested a dual circuit connection for the proposed new station by Q2 2018.

The need for this new station in northern Pickering was confirmed by the Needs Assessment study carried out by the GTA East Working Group as part of the regional planning process. Following the Needs Assessment, the Pickering-Ajax-Whitby Integrated Regional Resource Plan was initiated. The IRRP study team has reaffirmed the need for a new transformer station in the Seaton area by Veridian.

The project entails rebuilding a section of the 230kV single circuit line (C28C) out of Cherrywood TS as a double circuit line in order to provide a 230kV dual circuit connection for Seaton MTS from the 230kV circuits C28C and C10A.

Veridian is considering a number of sites and is currently seeking the necessary approvals for the new station site. The project is expected to be completed by June 2018.

Alternatives:
No alternatives to connection were considered, as failure to connect would place Hydro One in violation of its electricity transmission license.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:

To facilitate the customers' initiative to build a new Seaton MTS in North Pickering to supply new load growth anticipated for the new Seaton community.

Costs:

The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	3.3	3.0	7.1
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**3.3**	**3.0**	**7.1**
Capital Contribution	(2.2)	(1.9)	(4.8)
Net Investment Cost	**1.1**	**1.1**	**2.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Hanmer TS: Build 230/44 kV Transformer Station
Targeted Start Date: Q4 2016
Targeted In-service Date: Q1 2019
Targeted Outcome: *Customer Focus*

Need:
To increase transformation capacity to accommodate the forecast customer load growth and to improve supply reliability in the Greater Sudbury area, as documented in the Sudbury/Algoma region Needs Assessment report. Not proceeding with this investment would result in inadequate transformation capacity to supply customer demand in the area.

Investment Summary:
The Greater Sudbury area is supplied from Martindale TS, Coniston TS and Clarabelle TS. Coniston TS currently steps down voltage from 115kV to a non-standard sub transmission voltage of 22kV in order to supply part of the Sudbury East area. The Coniston TS facilities are reaching the end of their expected service life. The existing transformers T2 and T3 are in poor condition and are 75 and 66 years old respectively.

This project entails:
- Construction of a new 230/44kV transformer station with 50/83 MVA transformers at the existing Hanmer TS site;
- Conversion of the north-east Sudbury area supply to 44 kV; and
- Decommission the existing Coniston TS.

These measures will increase the loading capability to support future load growth and improve supply reliability. The conversion to 44kV allows for more load transfer capabilities with the other existing 44kV system. The project is expected to be completed by February 2019.

Alternatives:
Two alternatives were considered for providing additional capacity. These alternatives were:

- Alternative 1 – Rebuild Coniston TS and continue to supply the area at 22kV; or
- Alternative 2 – Build a new transformer station at the existing Hanmer TS site.

Alternative 2 is the recommended alternative as it meets the need with improved reliability at a lower cost.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased transformation capacity to supply load growth and to improve reliability in the Greater Sudbury area.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	9.5	18.5	30.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**9.5**	**18.5**	**30.0**
Capital Contribution	(1.7)	(3.4)	(5.6)
Net Investment Cost	**7.8**	**15.1**	**24.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits
Targeted Start Date: Q3 2016
Targeted In-service Date: Q1 2019
Targeted Outcome: *Customer Focus*

Need:
To increase the transformation capacity to accommodate the forecast customer load growth in the West Toronto area, as documented in the Metro Toronto Regional Infrastructure Plan. Not proceeding with this investment would result in inadequate transmission capacity to supply customer demand in the area.

Investment Summary:
Runnymede TS and Fairbank TS are two 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. These two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. The area is experiencing re-development and the proposed Eglinton Crosstown Light Railway Transit ("LRT") project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. The Metro Toronto Regional Infrastructure Plan has identified the need for additional step-down transformation capacity in the area.

The project entails:
- Construction of a new 115/27.6kV transformer station with two 50/83MVA transformers at the existing Runnymede TS site; and
- Upgrade of the 11kV circuits (K1W/ K3W/K11W/K12W) between Manby TS and Wiltshire TS.

This work will increase the existing capacity line and station capacity to meet forecast load demand. Hydro One will be required to apply for "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act*, and Class EA approval under the *Environmental Assessment Act*. The project is expected to be completed by February 2019.

Alternatives:
Two alternatives were considered for providing additional capacity. These alternatives were:

- Alternative 1 – Transfer loads to adjacent area stations; or
- Alternative 2 – Build a second transformer station at the existing Runnymede TS site.

Alternative 1 was not considered further due to the high cost and complexity of constructing new distribution feeders in Metro Toronto. Alternative 2 is the recommended alternative as it provides the needed capacity at the lowest cost.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased transformation and line capacity to supply load growth in the West Toronto area.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	23.0	17.0	47.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**23.0**	**17.0**	**47.0**
Capital Contribution	(10.5)	(8.0)	(21.8)
Net Investment Cost	**12.5**	**9.0**	**25.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Toyota Woodstock TS: Upgrade Station
Targeted Start Date: Q1 2017
Targeted In-service Date: Q1 2019
Targeted Outcome: *Customer Focus*

Need:
To facilitate the request from Toyota Motor Manufacturing Canada ("Toyota") to have dual supply capability at Hydro One's Toyota Woodstock TS. Hydro One is obligated under its electricity transmission license to make connections when requested by customers. Not proceeding with this investment would be a violation of Hydro One's transmission license.

Investment Summary:
The Toyota Woodstock TS exclusively supplies Toyota. The station consists of one 25/42 MVA transformer which is supplied by a single 115 kV circuit (B8W). Toyota has informed Hydro One that it requires the reliability benefits and operating flexibility of a dual supply station and has requested that Hydro One upgrade Toyota Woodstock TS accordingly.

This project entails extending the existing 115kV circuit (K7) by three circuit kilometers from Commerce Way TS to Toyota Woodstock TS and installing a second 25/42 MVA transformer at Toyota Woodstock TS.

Hydro One will be required to apply for "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act*. The project is expected to be completed by March 2019.

Alternatives:
No alternatives were considered, as failure to connect would place Hydro One in violation of its electricity transmission license.

Basis for Budget Estimate:
The project cost is based on budgetary project cost estimates prepared by Hydro One.

Outcome:
To facilitate the customers' request to improve reliability of supply with the addition of second supply into the Toyota Woodstock TS station.

Witness: Bing Young

Costs:

The project cost will be recoverable through capital contribution from the customer. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	3.0	2.5	6.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**3.0**	**2.5**	**6.0**
Capital Contribution	(3.0)	(2.5)	(6.0)
Net Investment Cost	**0.0**	**0.0**	**0.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Bing Young

Hydro One Networks – Investment Summary Document

Development Capital - Load Customer Connection

Investment Name: Enfield TS: Build 230/44 kV Transformer Station
Targeted Start Date: Q2 2017
Targeted In-service Date: Q2 2019
Targeted Outcome: *Customer Focus*

Need:
To increase transformation capacity to accommodate the forecast customer load growth and to improve supply reliability in the Oshawa – Clarington area. Not proceeding with this investment would result in inadequate supply capacity in the area.

Investment Summary:
The Oshawa – Clarington area comprises the eastern half of the GTA East Region and is supplied from Thornton TS and Wilson TS. The loading on Thornton TS already exceeds capacity while loading on Wilson TS is forecast to exceed capacity by summer 2018. The Local Planning Report[1] prepared as part of the regional planning process has identified the need for additional transformation capacity in the Oshawa – Clarington area.

This project entails construction of a new 230/44kV transformer station at the existing Clarington TS site. The station will include two 75/125 MVA step-down transformers and eight 44kV feeder breakers.

This work will increase the existing transformation capacity in the area by 170MVA. The project is expected to be completed by June 2019.

Alternatives:
Two alternatives were considered for providing additional capacity. These alternatives were:

- Alternative 1 – Build new transformer station at the existing Clarington TS site; or
- Alternative 2 – Build new transformer station at an unknown alternate site.

Both alternatives meet the needs of the area; however, Alternative 2 would require a new site which would have greater environmental impact and higher costs compared to building at the Clarington TS site. The Clarington TS site also better balances the needs of distributors with

[1] http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Local%20Planning%20Report%20-%20WilsonThornton%20-%2015_May_2015%20-%20Final.pdf

respect to feeder costs. A site other than Clarington would disadvantage one of the distributors by requiring them to build longer feeders. Alternative 1 was therefore recommended.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:
To provide increased transformation capacity to supply load growth in the Oshawa – Clarington area.

Costs:
The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.0	15.0	33.1
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**10.0**	**15.0**	**33.1**
Capital Contribution	(10.0)	(10.0)	(22.4)
Net Investment Cost	**0.0**	**5.0**	**10.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital –Load Customer Connection

Investment Name: TransCanada: Energy East Pipeline Conversion
Targeted Start Date: Q4 2018
Targeted In-service Date: Q4 2021
Targeted Outcome: *Customer Focus*

Need:
To provide a connection to TransCanada Energy's proposed Energy East pipeline pump stations. Hydro One is obligated under its electricity transmission license to connect any customer that requested connection to Hydro One's transmission system. Not proceeding with this investment would be a violation of Hydro One's transmission license.

Investment Summary:
TransCanada Energy ("TCE") plans to convert one of its existing Canadian pipelines from natural gas to oil. The Energy East pipeline will transport crude oil from Western Canada to Eastern Canadian refineries, with new pumping stations requiring electric power supply from all provinces along the route. In Ontario, nineteen new pumping stations will be built all requiring electric supply from the Hydro One transmission system. The pumping stations are located across Ontario. Five stations will be situated in Northwest Ontario (Kenora to Nipigon), nine stations in Northeast Ontario (Hearst to North Bay), and another five in Eastern Ontario (Pembroke to Cornwall).

This project entails the construction of line connections to each of the customer owned pump stations and modification of upstream facilities to accommodate this connection into the system. Transmission work is also required to facilitate the connection of two pumping stations at the distribution level. Hydro One is currently working with TCE to determine the specific connection scope required for each pumping station.

All pump stations must be in-service for the pipeline to operate at full capacity. The forecasted plan is for Hydro One to in-service the stations over the 2020 to 2021 period.

Alternatives:
No alternatives to connection were considered, as failure to connect would place Hydro One in violation of its electricity transmission license.

Basis for Budget Estimate:
The project cost is based on budgetary cost estimate prepared by Hydro One.

Outcome:
To provide connection for the pumping stations requested by TCE.

Costs:
The project cost will be recoverable through capital contribution from the customer. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.9	10.2	175.6
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**1.9**	**10.2**	**175.6**
Capital Contribution	(1.9)	(10.2)	(175.6)
Net Investment Cost	**0.0**	**0.0**	**0.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Development Capital - Protection and Control Modifications

Investment Name: Protection and Control Modifications for Distributed Generation
Targeted Start Date: Ongoing Program *(Various Projects)*
Targeted In-service Date: Ongoing Program *(Various Projects)*
Targeted Outcome: *Customer Focus*

Need:
To preserve the loading and protection capability of the transmission feeders, resulting from the connection of distributed generation. Not proceeding with this investment would be a violation of Hydro One's license which requires Hydro One to respond to connection requests.

Investment Summary:
Although at a much slower pace than the period from 2011 to 2015, Hydro One continues to receive requests from distributors to connect generation at the distribution level under a variety of IESO generation procurement programs such as the Feed-in-Tariff and the Combined Heat and Power Standard Offer Program. The connection of generation to the distribution systems supplied from the Hydro One transmission system requires a number of modifications and/or additions to the protection and control systems located at the transmission stations.

This program entails, but is not limited to, the following modifications and/or additions:

- Feeder Protection Replacement to preserve the loading capability of the feeders and provide directioning in order to prevent false tripping;
- Bus Protection Modification to prevent mis-operation;
- Line Back-up Protection Installation to protect transmission assets from distributed generators fault current contribution;
- Transfer Trip Signaling Installation to prevent distributed generation islanding and to coordinate with reclosing restoration;
- Station Telecom Facilities Installation to enable transfer trip signaling; and
- Station Telemetry Expansion to provide feeder telemetry and additional equipment alarms.

These measures ensure proper protection of transmission assets, reliability of supply to the distribution systems, and a safe interconnection for the distributed generators.

Alternatives:
No alternatives were considered, as failure to implement the modifications and/or additions would result in the inability to respond to connection requests.

Basis for Budget Estimate:
The program costs are based on a budgetary cost estimate prepared by Hydro One.

Outcome:
To allow the connection of renewable generation to the distribution systems throughout Ontario without deterioration in supply reliability while maintaining proper protection of the transmission assets and load carrying capacity of the transmission feeders.

Costs:
The program costs will be recoverable through capital contribution from the customers. The program costs and capital contribution amounts are considered preliminary as they are only finalized once the Capital Cost Recovery Agreement is signed and the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	6.0	5.5	11.5
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**6.0**	**5.5**	**11.5**
Capital Contribution	(6.0)	(5.5)	(11.5)
Net Investment Cost	**0.0**	**0.0**	**0.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Development Capital - Risk Mitigation

Investment Name: Nanticoke TS: New Station Service Supply
Targeted Start Date: Q3 2016
Targeted In-service Date: Q4 2017
Targeted Outcome: *Operational Effectiveness*

Need:
To provide a new station service supply to replace the existing sources from Ontario Power Generation Inc. ("OPG") at Nanticoke GS. Not proceeding with this investment would result in the inability to operate Nanticoke TS, forcing the station to be removed from service.

Investment Summary:
The AC station service loads at Nanticoke TS are supplied entirely by OPG's Nanticoke GS. The OPG AC station service supplies the power for Hydro One's autotransformer cooling, tap changer control, switchgear heating, etc., all of which are essential to the supply of reliable power from Nanticoke TS. OPG will cease to provide Hydro One with an AC station service supply based on the plans to permanently decommission Nanticoke GS station facilities as part of the Provincial Government "Off-Coal" initiative.

This project entails the construction of a new 600V AC station service supply fed from the 27.6kV tertiary winding of autotransformers T11 and T12 at Nanticoke TS. The station service system will include two 27.6/0.6kV transformers, two 27.6kV current limiting reactors and 600V low voltage bus and switchgear. The project is expected to be completed by December 2017.

Alternatives:
Two transmission alternatives were considered for providing station service supply at Nanticoke TS. These alternatives were:

- Alternative 1 – Provide station service supply from nearby step-down transformer station; or
- Alternative 2 – Provide station service supply from Nanticoke's 500/230kV autotransformers tertiary windings

Both alternatives meet the requirement. However, Alternative 1 would require long distribution feeders from Jarvis TS, would be more expensive and would have lower supply reliability. Alternative 2 is recommended as the tertiary connection provides the higher supply reliability at the lowest cost.

Basis for Budget Estimate:
The project cost is based on a budgetary cost estimate prepared by Hydro One.

Outcome:
To provide continued operation of Hydro One's network station at Nanticoke following the decommissioning of Nanticoke GS.

Costs:
The project cost will be recovered from the network rate pool as this system supports the operation of the Nanticoke TS 500kV and 230kV switchyard facilities that are network assets and no capital contribution is required from customers.

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	10.0	0.0	11.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**10.0**	**0.0**	**11.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**10.0**	**0.0**	**11.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Integrated System Operations Centre (ISOC) – New Facility Development
Work Execution Period: *04/2015* to *01/2020*
Targeted In-service Date: Q1 2020
Targeted Outcome: Operational Effectiveness

Need:
The Network Operating Divisions (NOD) Backup Control Centre (BUCC) no longer meets planned business or operational requirements to sustain monitoring and control operations to North American Electricity Reliability Corporation or Hydro One standards. The Backup Integrated Telecommunications Management Centre's (BUITMC) lacks the necessary capabilities to meet critical requirements due to location, activation timelines and equipment deficiencies. Hydro One Telecom Security Events Monitoring (SEM) requires a facility to provide planned 24/7 operations and growth. Security Operations (SOC) also requires a centre to mitigate reliance on third party services. Current facilities fail to provide needed space, equipment and availability while also being critical for Hydro One Operations and compliance.

This investment, formerly known as the Backup Control Centre – New Facility Development has expanded to include other operational synergistic lines of business that require facilities to perform critical operating, monitoring or control functions. Through an integrated solution, all critical infrastructures, office space and the site will be shared among lines of business with the intent of maximizing capital investments and reducing customer rate impacts. This investment will be governed through Hydro One's Affiliate Relationship Code.

It is essential to proceed with this investment to ensure continued compliance with regulatory requirements regarding having an operable Backup control facility with fully functional monitoring and operation control of the Hydro One Transmission system.

Investment Summary:
The Integrated System Operations Centre will house multiple lines of business through the provision of dedicated Control Centre, an integrated Data Centre and shared back office areas. This facility will be a hardened facility employing emergency preparedness criterion, industry best practices and heightened physical and cyber security standards. This strategy provides flexibility for Hydro One Networks and provides prudent capacity for future growth. These facilities are essential in maintaining adequate redundancy for Operation of the Bulk Electric System and the Telecom Communication Network and are mandated in North American

Electricity Reliability Corporation (NERC) requirement Emergency Operating Procedure 008-1 “Loss of Control Centre Functionality”. It ensures achievement of reliability and availability targets commensurate with the criticality of these facilities, while positioning Hydro One to respond to growth in Transmission, Distribution and Telecommunications. The ISOC will provide in-house security operations, mitigating reliance on third party services and also expand SEM services 24x7.

The ISOC design includes the following:

- Provides NOD with a new backup control centre including a control room, back office and a data centre, employing the following strategies:
  - Provide the operating flexibility that allows Network Operating to duplicate the current OGCC functionalities eliminating the limitations that exist today at the current BUCC;
  - Provide additional training synergies through the use of simulation technologies, allowing use of facilities while not required for backup activation (dual purpose); and
  - Ensure heightened security both physical and cyber.
- Provide the ITMC with a new backup operations control centre including a control room, back office and integrated computing facilities;
- Provide the Security Event Management centre with a primary operations control centre including control room, back office and integrated computing facilities; and
- Provide Security Operations with a headquarter location including a control centre, office space, investigative rooms and integrated computing facilities.

Alternatives:
Three alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Initiate build of BUCC and BUITMC only
- Alternative 3: Initiate build of the Integrated System Operations Centre

- **Alternative 1: Status Quo (Do Nothing)**

Hydro One Network Operating, Hydro One Telecom and Security Operations maintain existing facilities.

This alternative has been rejected as the current BUCCs for both NOD and ITMC do not meet operational requirements, impose a high level of risk to regulatory compliance, Hydro One's reputation and customer impacts, if additional failures are experienced. Additionally, this alternative fails to provide for SEMs and SOCs need for an adequate primary control centre for expanded operations.

- **Alternative 2: Initiate build of BUCC and BUITMC only**

Build Backup Control Centre's for Hydro One Networks and Telecom including shared critical infrastructure, back office support areas and an integrated Data Centre.

This alternative includes Control Rooms, an integrated Data Centre and shared back office support areas for prolonged activation and is considered the minimum requirement to address known operational risks that currently exist. In addition, this alternative includes the purchase of the preferred site. While this alternative meets Network Operating and the Integrated Telecommunications Management Centre's minimum requirements, it has been rejected as it fails to maximize investment utilization through synergistic lines of business occupancy as well as shared use of critical infrastructure.

- **Alternative 3: Initiate build of the Integrated System Operations Centre**

This alternative provides for a Network Operating Control Centre, as well as a Backup Control Centre for the Integrated Telecommunications Management Centre and primary facilities for Security Event Monitoring and Security Operations. This includes the provision for a shared integrated Data Centre, all critical support infrastructures and to build at the preferred site. This alternative will maximizing Operational flexibility for Hydro One Networks and associated lines of business by reducing the cost of building separate facilities, data centres and support infrastructures for these functions.

Basis for Budget Estimate:

A Planning Needs Assessment has been completed which includes conceptual blocking designs, architectural renderings with preliminary cost estimates. Additional support infrastructure (Power and Telecommunication Network connectivity) was estimated internally utilizing the various Engineering groups within Hydro One Networks.

Outcome:

This investment mitigates the critical risks (infrastructure failures, capacity constraints, location, and activation timelines) that exist at the Network Operating Backup Control Centre and the Backup Integrated Telecommunication Management Centre. By proceeding with this investment, availability and reliability of monitoring and control of the Bulk electric System (BES) will be sustained improving Hydro One's compliance posture. Additionally, the integrated solution will reduce the cost impact to our customers through the realization of economies of scales.

Costs:

($ Million)	2017	2018	Total
Capital* and Minor Fixed Assets	4.2	10.5	68.6
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**4.2**	**10.5**	**68.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.2**	**10.5**	**68.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Station Local Control Equipment Sustainment
Targeted Start Date: Q1 2017
Targeted In-service Date: Q4 2020
Targeted Outcome: *Operational Effectiveness*

Need:
This is a new annual program to fund and manage the end-of-life/end-of-support (EOL/EOS) replacement of local control and monitoring equipment at Hydro One stations. This equipment is required at every substation to meet local Power System Monitoring and Control (PSMC) operating requirements. This equipment enables field staff to operate a substation locally in the event that remote PSMC from the Ontario Grid Control Centre (OGCC) or Backup Control Centre (BUCC) is unavailable. This equipment must be replaced, due to the end of support from the vendor.

Investment Summary:
This investment will fund EOL/EOS replacement of the Station Local Control equipment at Hydro One stations. Replacement will be based on vendor selection in 2016. Replacements are planned to minimize operational risk prior to expiry of vendor support for software and hardware and historical end-of-life expectancy.

Alternatives:
EOL/EOS equipment can be replaced under a planned and scheduled approach or replaced upon failure. Replacing equipment on failure impacts OM&A costs reduces operational effectiveness and risks an increasing impact as more equipment fails prior to being replaced due to end-of-life. This can result in interruptions of a longer duration to customers and can affect safety. This alternative was rejected as the risks and uncertainty were deemed higher than a prudent planned approach to replacement.

Basis for Budget Estimate: Budgetary estimates are based on unit costs/preliminary estimates as well as historical costs for similar work.

Basis for Timing of Investment:
Notification of EOL/EOS from the vendor and the time requirement for installation and replacement of base equipment are considered in identifying the timelines for the commencement and pacing of the replacements.

Witness: Andrew Stenning

Outcome:

This replacement program of EOL/EOS station local control equipment will minimize operational risk to allow swift local reaction to any contingencies that may affect reliability or safety. The level of investment has been determined based on the fleet size and age of existing equipment and recent unit cost estimates.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	3.6	3.7	7.3
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**3.6**	**3.7**	**7.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.6**	**3.7**	**7.3**

*Includes Overhead at current rates. No Allowance for Funds Used during Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Grid Control Network Sustainment Program
Targeted Start Date: Q4-2014
Targeted In-service Date: Q4 2018
Targeted Outcome: Operational Effectiveness

Need:
To replace end of life/end of support ("EOL/EOS") elements of the Grid Control Network such as routers, switches and gateways which support hubsite and station LAN infrastructure. Equipment replacement is also required to meet compliance and security requirements due to functionality or limitations of the device.

Investment Summary:
This is an ongoing program to manage the EOL/EOS replacement of Grid Control Network elements. Replacement is based on vendor announcements, and/or end-of-life due to increased functionality requirements and replacements are planned to minimize operational risk prior to expiry of vendor support for both hardware and software.

Alternatives:
EOL/EOS equipment can be replaced under a planned and scheduled approach or replaced upon failure. Replacing equipment on failure impacts OM&A costs, reduces operational effectiveness and risks an increasing impact as more equipment fails prior to being replaced. This alternative was rejected as the risks and the uncertainty were deemed higher than a prudent planned approach to replacement.

Basis for Budget Estimate:
Budgetary estimates are based on unit costs/preliminary estimates as well as historical costs for similar work.

Basis for Timing of Investment:
Install base of equipment, time frame to replace, and time frame to comply with new requirements as well as notification of EOL/EOS from the vendor are considered in identifying the start of the work, the duration and required completion of the work.

Outcome:

The level of investment has been determined based on a balanced financial and resource commitment to ensure all equipment is replaced prior to EOS to minimize operational risk

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	5.8	3.0	8.8
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**5.8**	**3.0**	**8.8**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.8**	**3.0**	**8.8**

*Includes Overhead at current rates. No Allowance for Funds Used during Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Information Technology Capital

Investment Name: Hardware/Software Refresh and Maintenance
Target Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: Operational Effectiveness

Need:
Investment levels are needed to ensure that critical systems are available and can survive the failure of any single supporting technology component. Investments in supporting technology components, including telecom and IT hardware and software, must also be maintained to benefit from vendor support so that they can be fixed and/or replaced expeditiously in the event of failure. To that end, Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program ensuring vendor support is available and decreasing the likelihood of failure. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

Investment Summary:
Included in 2017 and 2018 planned costs is the implementation of enterprise resource planning applications and tools, further IT security access control and monitoring capabilities, middleware and databases and productivity tools, server upgrades to keep the data center infrastructure vendor supported and to make improvements to the disaster recovery platforms.

Alternatives:
There are no viable alternatives as vendor support is required on critical systems.

Not proceeding with the current lifecycle asset refresh or reducing funding beyond the current level will significantly increase risk to reputation (increase in employee dissatisfaction due to frequent and/or prolonged service outages), regulatory relationship (disruption to market operations due to IT systems that interact with market participants), customer/reliability (increase in customer dissatisfaction due to failure of enterprise wide applications such as SAP, ihub/Tivoli, Microsoft Exchange, mobile applications, customer billing, relationship management, and call centre systems; and failure to meet service quality index for customer service), and competitiveness (high unit cost of supporting and servicing applications without vendor support).

Basis for Budget Estimate:
Based on historical costs and vendor discussions.

Outcome:
This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investments for problem resolution. This investment in IT system reliability enables general employee productivity because users have access to the tools they require to work, and it enables customer satisfaction through availability of enterpise wide applications, customer call centre and outage management systems.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	5.1	5.1	10.2
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**5.1**	**5.1**	**10.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.1**	**5.1**	**10.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Information Technology Capital

Investment Name: MFA Servers and Storage
Target Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: Operational Effectiveness

Need:

This investment is required to respond to and manage annual growth in demand for additional IT processing and storage capacity and to address end of life issues with the existing Unix and Wintel servers.

Infrastructure servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. Servers and storage devices reach capacity over time and reach their vendor's end-of-support-life at which time they require upgrading or replacement to increase capacity or to ensure cost efficient maintenance that minimizes or eliminates down time. In determining when systems require replacement, the functionality and operating and maintenance costs are assessed. The funding for the servers and storage refresh program varies year over year depending on hardware lifecycles and business requirements for increased processing capacity.

Investment Summary:

Wintel servers are refreshed on a three- to five-year cycle and UNIX servers are refreshed on a five- to seven-year cycle. These cycles fall within industry best practices and maintain warranties within an acceptable level. The replacement cycle for refresh of Wintel and Unix servers is to maintain vendor-supported levels and includes hardware upgrades, capacity upgrades for core access control and middleware environments in anticipation of increased data processing with SAP-driven processing. Costs in 2017 and 2018 reflect typical lifecycle refresh of end-of-life storage hardware.

Alternatives:

There are no viable alternatives as vendor support is required on critical systems.

Not refreshing end-of-life servers or delaying investment in storage devices beyond the current level will impact the reliability of IT systems and increase the incidents of failure. It will also drive additional sustainment costs, as many vendors charge time and materials to support end of life products. It will remove the ability to build out capacity on demand capability which will lessen the ability to provide hosting for new or expanded IT services in a timely fashion.

Witness: Gary Schneider

Basis for Budget Estimate:
Historical costs provide a trend and basis for budget estimation, in addition to vendor discussions for future demand manangement driven by development projects/programs.

Outcome:
IT system availability directly impacts the productivity of employees who use the technology, and prevents risks to the availability and security of the power network. This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investment for problem resolution. It also reduces the risk to Hydro One's ability to respond to business requirements and project delivery due to IT system integration and scalability impacts.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	4.2	2.8	7.0
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**4.2**	**2.8**	**7.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.2**	**2.8**	**7.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Information Technology Capital

Investment Name: Work Management & Mobility
Target Start Date: Q1 2014
Targeted In-service Date: Q4 2019
Targeted Outcome: Operational Effectiveness

Need:
The existing processes and applications used to manage work within the provincial lines, stations and forestry organizations involve significant manual effort and paper processing. This creates inefficiencies, time delays and data inaccuracies.

All work and information needs to be scheduled, dispatched, executed and reported through a standard set of processes and technologies across all of these lines of business within Hydro One. For example, the existing applications used by the provincial lines organization to schedule, dispatch and report work lacks the functionality and integration to support the productivity gains that are possible.

Work for the provincial lines organization is presently underway. This was described in the investment summary document IT-04 ("Field Workforce Optimization and Mobile IT"), which was provided in Attachment 1 of Exhibit I-10-14 filed in support of Hydro One Transmission's 2015-2016 revenue requirement application (EB-2014-0140).

Investment Summary:
Through a competitive procurement process in 2014, the decision to standardize using SAP's mobile capabilities was made, and a systems integrator was retained to help configure and deploy the solution across the provincial lines organization. A commitment to achieve at least a five percent productivity gain was established, with a projected return on investment of 21.3% and projected annual savings of $12 million. This project is currently under way with an in-service date in the first quarter of 2017.

Subsequent projects for the stations and the forestry organizations are expected to mobilize in 2017, using the standard business and technical solutions established during the provincial lines project.

This investment will streamline Hydro One work management processes and deliver an enhanced, integrated scheduling, dispatching and mobile solution for the three lines of business, achieving significant productivity benefits in each.

The projects for provincial lines, stations, and forestry organizations will involve implementing the following:

- SAP's mobile technology for use by Hydro One's field workforce;
- new/upgraded planning & scheduling software, integrated with SAP and the SAP mobile capability;
- SAP mobile platform integration with Hydro One's geographical information system (GIS); and
- standardized processes for work planning, scheduling, dispatch, execution and reporting.

Alternatives:
Maintaining the Status Quo - This alternative was considered and rejected as a result of the following:

- taking no action would leave Hydro One with suboptimal systems for planning and scheduling resources, and manual and untimely paper processes for recording work accomplishments;
- dispatchers would not be able to leverage geospatial capability related to the location of assets, crews and work;
- the existing mobile platform would remain inconsistent with SAP's future direction;
- data entry would remain labor intensive, and errors and poor data quality would continue to be prevalent; and
- the potential significant productivity gains would not be realized.

Basis for Budget Estimate:
Based on historical costs of similar projects.

Outcome:
These projects will provide the schedulers and field staff with real-time or near real-time work status update capability, present staff with a consolidated view of work information, provide a geographic scheduling tool on mobile devices, and enable timely, quality data capture at source.

These projects will also provide a near paperless and automated work environment which will help save paper and fuel, reduce vehicle emissions as well as save corporate operation expenses. Reducing manual steps and providing data validation at time of entry, will result in higher data quality and increased staff productivity.

In addition to a minimum five percent productivity gain for the field workforce, there are also qualitative benefits in the areas of employee safety and customer service.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	5.9	3.3	32.6
Operations, Maintenance & Administration and Removals	(0.9)	(0.3)	(3.6)
Gross Investment Cost	**5.0**	**3.0**	**29.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.0**	**3.0**	**29.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Common Corporate Capital

Investment Name: Real Estate Field Facilities Capital
Targeted Start Date: Q1 2017
Targeted In-service Date: 2018 to 2020
Targeted Outcome: Operational Effectiveness, Public Policy Responsiveness

Need:
The capital investment is required for field facilities to comply with legal requirements and provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business. Investment needs are driven by the following key factors:

- aging facilities that are at or near the end of life;
- compliance with current legal requirements, such as *Accessibility for Ontarians with Disabilities Act* (Ontario);
- expanding work programs;
- new accommodation needs;
- evolving work practices;
- improved health and safety;
- improved security;
- sustainable development; and
- work efficiency and productivity

Approximately 40% of administration and service centre facilities infrastructure is estimated to be more than 40 years old. The facilities are largely undersized, ill configured, and underperforming to current operational requirements, resulting in increasing operating costs for maintenance and repair and presenting an ongoing inefficiency to facility and business operations.

The field facilities capital work program focuses on undertaking facility work entailing improvements, additions or new facilities on a priority and timely basis at a level of expenditure required to minimize the risk to business operations to fully deliver the prescribed various work programs in a safe, efficient and cost effective manner. This work is conducted on a project basis.

Investment Description:
The field facilities capital work program addresses portfolio accommodation needs in terms of facility improvements, building additions and new facilities, as determined by Hydro One's operational requirements. This program ensures that essential and supportive improvements are made to administration and service facilities that minimize building and site-related risks to the operations; serve operational requirements; and promote efficiencies in the maintenance and operation of the facilities in the longer term.

The project entails:

- addressing accommodation requirements in terms of new buildings, buildings additions and major facility renovations; and
- replacing major building components including: roof structures, windows, HVAC systems and other structural elements and building systems.

A capital investment of $18.4 million is required for 2017 and $20.9 million for 2018. These amounts are needed to fund new accommodation solutions, address needs for new buildings, buildings additions, and facilities improvements, as required by the company's work programs.

The locations targeted for investments starting in 2017–2018 are set out in Table 1. Projects can be multi-year projects, and work is contingent on obtaining the requisite municipal planning approvals.

Table 1: Planned Investment Locations

Project Name	Planned Investment	Start Year
Dryden Operation Centre (New)	New facility to replace existing undersized and end of life facility, i.e. Dryden Service Centre.	2017
Dryden Garage (New)	New facility to replace existing undersized, ill equipped and end of life facility, i.e. Dryden Garage.	2017
Dryden Hanger (New)	Replace leased facility that is inadequate (undersized and shared with third parties) for operations.	2018
Arnprior Garage (New)	New facility to replace undersized facility, i.e. Arnprior Garage (located within former Arnprior Service Centre).	2018
Stirling Station Maintenance Work Centre	Replace existing leased Campbellford Service Centre, which has been highly constrained by a successive series of ongoing building area reductions by Ontario Power Generation.	2017
Renfrew Station Maintenance Work Centre	Relocate Station Maintenance crew from Ottawa to Renfrew to reduce the considerable loss of time for daily travel to the region.	2017

Alternatives:

The development of each of the field facilities entails a comparative evaluation of alternatives, which may entail leasing, or purchasing (existing) suitable and greenfield developments against status quo condition. The objective is to pursue the most cost effective strategy that addresses operational requirements and manages risk. Operational considerations are for both existing and future requirements, where the latter considers changes to the business, e.g. volumes and delivery strategy.

Basis for Budget Estimate:

Capital investment is based on historical costs adjusted from project scope, local conditions and prevailing market pricing.

Outcome:

The investments will result in compliance in applicable legal requirements and improved productivity resulting from having:

- secured necessary accommodation space in the field in line with work programs requirements; and
- better administration and service centre facilities through replacement of roof structures, windows, heating, ventilating and air conditioning (HVAC) systems and other structural elements.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	18.4	20.9	39.3
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**18.4**	**20.9**	**39.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**18.4**	**20.9**	**39.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Hydro One Networks – Investment Summary Document

Common Corporate Capital

Investment Name: Transport & Work Equipment
Targeted Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
Transport and Work Equipment ("TWE") expenditures for 2017 through 2018 are required primarily to: replace core TWE at end of life; support the growing levels of transmission and distribution capital and OM&A Sustainment, Development and Operations work programs to support the forestry mechanical brushing program and provincial lines pole replacement program; and replace deteriorating helicopters with newer safer and more capable helicopters.

Investment Summary:
Hydro One controls and manages approximately 7,800 transport and work equipment vehicles which support the various lines of business, including provincial lines, stations, forestry and construction services organizations. Fleet vehicles must be maintained at an optimum level to ensure public and employee safety and compliance with laws. These include, but are not limited to CSA 225, the *Highway Traffic Act* and the Commercial Vehicle Operator's Registration regulations. This results in minimized environmental impacts and optimized line-of-business productivity by minimizing downtime, travel time, and by optimizing technology and continuous improvement opportunities.

Fleet capital replacement requirements are based on industry standards (manufacturer's recommendations) for life cycle expectancy, net book value (NBV) to original capital value (OCV) ratios and operating cost drivers, which are then linked to the investment plan and work programs. Currently the fleet is at 39% NBV to OCV where industry standards suggest 45% as an optimum level. Hydro One's present replacement criteria are based on manufacturers' recommendations and repair history.

Key drivers behind the 2017-2018 capital program include:

- primarily, the replacement of core TWE;
- additional vehicle and equipment requirements to support the mechanical brushing program;

- additional vehicle and equipment requirements to support the provincial lines pole replacement program; and
- replacement of a helicopter in 2017 that is in a deteriorated condition and a progress payment in 2018 to replace a second helicopter.

Alternatives:
Given the wide reaching and integral role transport and work equipment plays in the day-to-day operations, safety and success to Hydro One, few alternatives are available to investment in TWE assets.

The primary alternative is a reduction in capital spending on TWE. However, lowered investment results in increased rentals used to offset work program requirements, increased maintenance costs, vehicle downtime and decreased availability for utilization.

Basis for Budget Estimate:
Market pricing is the basis for the estimates. Fleet capital requirements are primarily based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining capital value, and operating cost drivers. Light vehicles are replaced after six years or 180,000 km, service trucks are replaced after six years or 300,000 km, and work equipment is replaced after eight to ten years or 400,000 km.

Outcome:
This investment will:

- ensure compliance with all safety standards, as well as Ministry of Transportation and other regulatory requirements;
- allow Hydro One to maintain and improve its present core fleet level of 39% vs. the 45% NBV to OCV established through a combination of Canadian Utility Fleet Manager workshops, direction from fleet management companies and industry experts;
- maximize productivity and utilization;
- maximize equipment availability;
- optimize repair time and fleet size; and
- maximize efficiency and life cycle benefits.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	20.9	21.8	42.7
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**20.9**	**21.8**	**42.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**20.9**	**21.8**	**42.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Witness: Gary Schneider

Hydro One Networks – Investment Summary Document

Common Corporate Capital

Investment Name: Service Equipment
Targeted Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: Operational Effectiveness

Need:
Minor fixed asset (MFA) expenditures for service equipment for 2017 through 2018 are required to support the growing levels of transmission and distribution capital and OM&A sustainment, development, operations work programs and to replace end of life and obsolete equipment.

Investment Summary:
MFA spending for service equipment consists of capital items of $2,000 or more, required by Hydro One staff to carry out construction and maintenance work programs. MFA expenditures for service equipment are required to replace equipment at end of life, replace technologically obsolete service equipment when new standards and safer work practices come into effect, and provide for sufficient levels of new service equipment consistent with work program expansion.

Purchases in this category include:

- specialized transportation equipment such as all-terrain vehicles, boats, barges, snowmobiles and related accessories to transport crews to off-road work sites;
- measuring and testing equipment to carry out a variety of work activities such as trouble shooting, performance testing of equipment, wood pole density testing, battery testing, relay test systems, moisture analyzers, circuit breaker testers, and resistance testers;
- tools and a wide range of other miscellaneous equipment such as PCB waste bins, portable generators, cabling trailers and equipment, satellite equipment for mobile emergency preparedness, insulator power washing equipment, automated external defibrillator devices, conventional line tensioning puller ropes and maintenance shop equipment to describe a few; and
- mobile equipment includes relatively large tanker units utilized in the service of transformers including SF6 gas carts, degasifiers used to remove impurities from insulating oil, heated oil tankers, oil filters, oil farm upgrades and dry air machines.

MFA service equipment requirements will vary year to year depending on a number of factors including the overall asset condition, the number of large cost “one-time” items that occur from year to year, the size of the work program and associated staffing levels projected in the business plan, random equipment failures, unanticipated system impacts, weather severity, and trends which affect the intensity and use of certain types of equipment, particularly related to storm and trouble call programs.

Spending in 2017 through 2018 is focused on the level of equipment required to accomplish the growth in overall transmission and distribution work programs, and end of life replacements. Spending is largely due to the stations services organization repairing and replacing oil shipping tankers, mobile degasifiers and railcar movers.

Alternatives:
The primary alternative is a reduction in capital spending on service equipment. However, lowered investment here results in increased rentals used to offset work program requirements, increased maintenance costs, and delays in the completion of work programs.

Basis for Budget Estimate:
Construction and maintenance work program requirements create the need to replace end of life, or technologically obsolete service equipment when new standards and safer work practices come into effect, providing for sufficient levels of new service equipment consistent with the work program.

MFA service equipment requirements will vary year to year depending on a number of factors including the overall asset condition, the number of large cost “one-time” items that occur from year to year, the size of the work program and associated staffing levels projected in the business plan, random equipment failures, unanticipated system impacts, weather severity, and trends which affect the intensity and use of certain types of equipment, particularly related to storm and trouble call programs.

Outcome:
This investment will:

- maintain equipment and tool fleets at the required levels to accomplish the growing levels of capital and OM&A sustainment, development and operation work programs in 2017 through 2018;
- reduce operating costs; and
- increase efficiency and reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	3.2	3.2	6.4
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**3.2**	**3.2**	**6.4**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**3.2**	**3.2**	**6.4**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Witness: Gary Schneider

CAPITAL WORK EXECUTION STRATEGY

1. INTRODUCTION

Every year, Hydro One aims to complete its annual work program - a series of multi-year projects and programs for which expenditures will be occurred in that calendar year. Hydro One's annual work program is subject to the relevant year's OEB-approved amounts for both net capital expenditures and in-service additions. Hydro One's Transmission Capital Work Execution Strategy has been able to demonstrate that it can accomplish a very large work program, while maintaining the needed flexibility to accommodate any required adjustments in that capital work plan due to project challenges (e.g. outage constraint, external approvals, material delivery, site conditions), customer needs, changing priorities and emergent investments. A focus on the company's business objectives including safety, quality, efficiency, and meeting customer commitments strongly influences Hydro One's work planning and execution activities.

Hydro One successfully completed its largest-ever capital work program in 2015 and is on track to complete a similar-sized work program in 2016 as a result of recently implemented improvement initiatives. Fully executing the work program is essential in continuing to meet the transmission performance expectation of customers. The new bundling approach to work has optimized planned outages, addressing a key concern for transmission customers according to Hydro One surveys. Safety performance is steadily improving, resulting in the lowest level of recordable incidents in over ten years. Additional metrics to track the performance of the capital work program can be found in the proposed transmission scorecard and the Cost Efficiencies, Productivity and Key Performance Indicators exhibit, Exhibit B2, Tab 1, Schedule 1.

2. ABILITY TO EXECUTE

Hydro One has worked to ensure that the timing of its capital investments and in-service additions matches the timelines proposed in the EB-2014-0140 proceeding, while being flexible enough to respond to changing priorities and emerging needs.

Building on the current momentum, additional initiatives will be implemented during the 2016-2018 period to ensure that the increased capital work program is accomplished in a cost-effective and reliable manner, with reduced variability at the investment level, and in-line with regulatory expectations. The initiatives identified in this document are the culmination of an end-to-end review of the capital work processes, and impact the two main areas of the capital work program lifecycle: project definition and project execution. For the OEB approved and actual total amounts of in service additions for historical years (2014 and 2015), as well as forecast additions in bridge year (2016) and test years (2017 and 2018), please see table 1 in Exhibit D1, Tab 1, Schedule 2.

3. COST DRIVERS OF THE CAPITAL WORK PROGRAM

The cost of the Capital Work Program is comprised of: i) material; ii) construction labour, fleet and equipment; iii) contracts; iv) engineering and project management; v) commissioning and vi) interest and overhead. Hydro One is continually looking for cost efficiencies and productivity improvements to offset the increasing costs of these six drivers.

3.1 Materials

Materials represent approximately 30% of total capital work program costs. Hydro One manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a company-wide basis using cross-functional teams to manage the supply base. The methodology's five-step process includes spending analysis, market analysis and development of a sourcing strategy, negotiation, award, and contract/services management. Efficient and effective sourcing of materials also includes Demand Planning in collaboration with Operations. For Supply Chain initiatives and value realization, see exhibits; Exhibit C1, Tab 5, Schedule 1 and Exhibit B2, Tab 1, Schedule 1 respectively.

3.2 Construction Labour, Fleet and Equipment

Construction labour, fleet and equipment costs represent approximately 20% of total capital work program costs. The field construction groups lead a diverse workforce of construction building trades to safely and cost effectively sustain and develop the transmission system. With a service territory that covers the province and over 200 in-flight projects to oversee, there are many challenges to successfully deliver top quality products. All construction labour (casual trades) is unionized in the province and therefore the same unionized labour rates apply whether the work is managed internally or externally. Hydro One engages staff through the hiring hall to meet work demands across the province, and the workforce works for ten hours, four days a week to save on travel costs associated with the expansive service territory and also reduce 'windshield' (travel) and down time.

3.3 Contracts

Contracted Services represent approximately 15% of total capital work program costs. The Contracted Services category includes contracts for a wide variety of external services that help deliver the transmission capital work program including: third party

EPC (Engineer, Procure & Construct) agreements for select projects, specialty construction skills that are not retained within Hydro One (i.e. tunnelling, high voltage cable installation, etc.), and specialty equipment rentals with operators (e.g. cranes, day lighting / vacuum trucks, etc.). Services are competitively procured on either a project-by-project basis (e.g. for EPC projects), or using a master service agreement structure for others. Ongoing continuous improvement in this area is focused on refining the contract management processes and utilization of commercial levers to optimize spend.

3.4 Engineering and Project Management

Engineering and Project Management represents approximately 15% of total capital work program costs. The Engineering function provides key inputs into project definition and produces the standards, designs, and equipment specifications to support procurement and construction activities for Sustaining and Development investments. Deliverables are produced using a mix of internal and external resources, with an increasing volume of external work. Key efficiency and productivity focus areas have been process and organizational enhancements to improve on-time delivery, establishment of quality assurance systems, and restructuring of third party contracts to improve cost effectiveness and overall value.

The Project Management function provides end to end coordination and governance to ensure that projects are delivered according to project plan, including scope, cost, and schedule. This cost category is comprised of internal Hydro One resources generally covering project management, estimating, construction and quality assurance. Throughout early 2016, Hydro One has been working with a strategic partner to support the continuous improvement of project management tools and processes.

3.5 Commissioning

Commissioning represents approximately 5% of the total capital work program costs. Commissioning is the process of assuring that all systems and components are designed, installed, tested, operated, and maintained according to the operational requirements. The commissioning team validates the functionality through formal site acceptance testing.

3.6 Interest and Overhead

Interest and Overhead represent approximately 15% of total capital work program costs. Hydro One's interest capitalization rate is based on the embedded cost of debt that is used to finance its capital expenditures. This is consistent with Hydro One's adoption of United States Generally Accepted Accounting Principles ("US GAAP") per the Board's decision in EB-2011-0268 and US GAAP requirements for the determination of interest capitalized. The rates used in calculating capitalized interest for the bridge and test years represent the effective rate of Hydro One Transmission's forecasted average debt portfolio during the year.

Hydro One capitalizes costs that are directly attributable to capital projects as well as overheads expended to support capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year. At year-end, capitalized overheads are trued-up to reflect actual results.

4. CAPITAL PROJECT PROCESS OVERVIEW

The Capital Project process is comprised of two key stages, Project Definition and Project Execution, with a governance structure overseeing the entire process.

4.1 Project Definition

Objectives of the Project Definition phase are to identify project needs, develop project scope as discussed in Investment Planning Process (see Exhibit B1, Tab 2, Schedule 1); as well as produce a conceptual and detailed design, estimate the costs of the project, and produce a preliminary project plan. It involves the asset management, engineering and estimating functions of Hydro One. This stage includes input from many key stakeholders including customers, Hydro One's real estate, project management, construction services, operating, and station maintenance workgroups, and external agencies.

4.2 Project Execution

Project Execution encompasses several workgroups within the Engineering and Construction Services organization working in concert with other lines of business and ancillary teams to deliver the transmission capital work program. The four stages of Project Execution are described in sections 4.2.1 to 4.2.4. Overall project oversight, coordination, and control are provided by the Project Delivery and Work Program Management groups by a team of experienced project managers and support staff to ensure that projects are executed within the defined scope, budget, and planned timelines.

4.2.1 Detailed Engineering and Procurement

Once an investment is approved in accordance with the Executive Authority Registry, it proceeds to the detailed production engineering phase. The output of this stage involves the development of detailed design packages, environmental approvals, and major equipment procurement. Upon substantial completion of production engineering and the procurement of major materials and services, the expectation is that most of the potential variability is removed from the project, and as such there is a reasonable expectation that key elements such as cost to compete, planned accomplishments, schedule completion dates and other major execution milestones will be met, barring extraordinary circumstances.

4.2.2 Construction

The goal during the construction phase is to build the required technical standards and detailed engineering specification in a manner that is safe, cost effective, high quality and in compliance with regulatory and environmental requirements. Detailed job planning and daily tailboards are emphasized as key communication elements at every stage of the process, from site preparation and civil / electrical work to major equipment installation and site remediation activities.

4.2.3 Commissioning

Following a formal hand-off at the end of the construction stage, formal testing and commissioning commences, to provide quality assurance and assess readiness for transfer of control to Ontario Grid Control Centre. This critical step is performed by the Stations and Operating division, which has overall accountability for operating the power system and for the safe and efficient execution of all assigned work related to the operation and maintenance of the transmission and distribution systems.

4.2.4 Project Closure Process

Starting in 2015, capital projects with a budget of $5 million or greater are subject to a combined Project Close Out and Lessons Learned site meeting to ensure that the project objectives have been met. The project closure process engages key participants throughout the capital work program life cycle to ensure knowledge transfer for future projects and to establish a culture of continuous improvement.

4.3 Governance

A robust cross-functional governance structure is in place and consists of internal Engineering and Construction Services resources as well as parties within the Finance, Asset Management and Executive functions. Investments are monitored and scrutinized at multiple levels to ensure that material changes to scope, cost or schedule are identified, properly approved, and mined for lessons-learned to prevent re-occurrence. A combination of standard reporting requirements, key performance indicators, change management approval processes, and monthly review of the capital work program both at the project and portfolio level provides assurance that projects are being well managed.

5. PRODUCTIVITY AND EFFICIENCY IMPROVEMENTS, PROJECT DEFINITION

A number of continuous improvement initiatives have been undertaken to increase effectiveness and efficiency of the capital work program delivery, and are outlined in the following sections.

5.1 Integrated Planning

Hydro One changed its approach to planning, monitoring and executing its sustainment capital work program beginning in 2014. At a high level, the integrated investment planning approach involves bundling work at an individual station or line segment level rather than the asset level. It has been implemented across the transmission sustainment capital portfolio, which has streamlined the end-to-end project lifecycle. The station-centric and line-centric approach has reduced the number of mobilization and demobilization activities, and optimized outages, maintenance requirements, and engineering and project management processes. For further details of sustainment capital portfolio refer to Exhibit B1, Tab 3, Schedule 2.

5.2 Enterprise Engagement during Investment Plan Development

Hydro One has made significant efforts to increase the participation of the executing lines of business in the planning process to ensure the investment plan is realistic and achievable in its entirety. The level of detail provided in planning has improved to include actual and future customer commitments, external approval requirements, and more detail on the assets being replaced. Executing lines of business are provided with more time to review the projects with the Planning organization to clarify assumptions. They are also able to identify interim milestones for project definition stages that will set the organization up for success as well as provide the ability to monitor these milestones and identify challenges earlier in the process. All of this information has assisted the executing lines of business in planning their work execution strategy and expanding their planning horizon.

5.3 Stronger Stage Gate Process

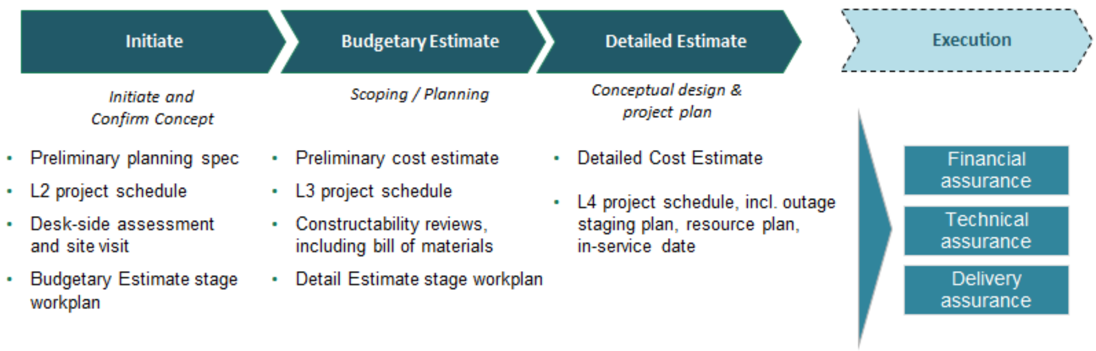

Figure 1: Stage Gate Process

Hydro One has taken steps to increase the level of accuracy of its estimates prior to project approval. The majority of capital investments follow a two-stage estimating process which is intended to give an increasing assurance of scope, schedule and cost, resulting in an increasingly accurate project plan and cost prior to approval.

In order to achieve a greater degree of accuracy in its estimates, Hydro One has focused on improvements to upfront project definition process and deliverables to minimize the implementation risks and increase estimating accuracy. This approach generally advances several project activities earlier in the investment lifecycle to support a more defined project plan and estimate. Such activities include additional engineering to minimize technical assumptions made during the estimating phase, greater consideration to procurement needs for major equipment, and additional consideration to project staging & outage requirements. New process steps ensure that internal stakeholders are engaged upfront to provide timely input to enable successful outcomes (i.e., input and design reviews for constructability, operability, maintainability, consideration to safety improvements, and minimizing environmental impacts).

Hydro One has placed a renewed emphasis on deliverable completeness and quality across all estimating stage gates, and has implemented a multi-disciplinary estimate review committee at the director level to scrutinize assumptions, share knowledge, and reach alignment on the estimate and risks. These changes are intended to increase confidence in the project plan including scope, schedule and cost to increase technical and financial certainty and reduce variability within individual projects and the broader Transmission Capital portfolio.

5.4 Estimating

Hydro One has been working to improve the estimating process and methodologies with significant changes implemented in 2015. The company has adopted the practice of setting an annual escalation rate of 2.3% for 2017 and 2.5% for 2018 and a maximum contingency rate of 10% of a project's estimate, respectively. These thresholds are in line with the industry norms, and are an improvement from prior practices where contingency could be as much as 20%. Hydro One has accomplished this by modifying the estimating process to complete a greater portion of conceptual engineering upfront, thereby minimizing the uncertainty inherent in the estimating process.

In consultation with an industry leading project management partner, Hydro One has approved an initiative to further improve the estimating processes and methodologies, which includes a new estimating tool that will be operational in late 2016. This initiative will increase the quality of estimates at each stage in the investment life cycle through new internal trending and analysis capabilities. Hydro One is also investigating a new process to monetize project risk so that the contingency can be more accurately defined and released as the project progresses and risks either materialize or are mitigated.

5.5 Engineering

A key dependency of successfully delivering the transmission capital work program in its entirety is the timely completion of quality engineering work as a predecessor to procurement and construction activities. Hydro One has made a number of process and organizational improvements resulting in increased engineering output and these improvements have contributed to the continued trend to successfully accomplish an increasing transmission capital work program. Substantial work has been done to standardize engineering processes and design packages, resulting in improved on-time delivery rates and overall cost effectiveness. Improved organizational alignment of different engineering functions has enabled more integrated solutions across project definition and project execution phases.

With the increasing Transmission capital work program, there continues to be an increasing need to utilize external engineering partners. The portion of the engineering portfolio completed externally has continued to grow over recent years, from roughly 14% in 2012 to roughly 25% in 2015. In addition to increased capacity through additional engineering resources, the external utilization has a cost efficiency element as fully burdened external labour rates are lower than fully burdened internal labour rates

Although there are cost savings associated with external engineering partners, Hydro One Engineering is essential in the development of the engineering standards, equipment designs and material designs that ensure safety, efficiency, quality and consistency to meet regulatory and compliance requirements (e.g. NERC, IESO, NPCC, CSA, etc.). Engineering's extensive knowledge of the Hydro One transmission system allows the group to diagnose system problems accurately and efficiently and provide support to other lines of business to quickly remedy emergency/break fix issues. Hydro One

Engineering prepares the technical specifications that feed external Engineering, and acts as Owner's Engineer to ensure quality and compliance.

External engineering partners are participating in a robust quality management system to ensure that the resultant third party work meets the needs of Hydro One.

Through a combination of internal and external engineering resources, Hydro One is working to complete both an increasing volume of engineering work as well as advancing engineering deliverables earlier in the project lifecycle to create an intentional backlog of construction-ready projects. As a result of this improved overall readiness, there will be increased technical, financial, and strategic assurances.

5.6 Advanced Readiness

Hydro One has concentrated its effort on implementing continuous improvement initiatives in the front-end of the investment lifecycle, when there is a greater opportunity to influence a successful project outcome. The objective is to have a larger portion of the capital portfolio in a more mature state to minimize variability in project scope, cost, and schedule. Process improvement during the initial stages of an investment (e.g. engineering and estimating) enables improved readiness in the later stages (e.g. procurement and construction) where the majority of the capital expenditure occurs. The result is increased technical and financial assurance for individual projects and the entire capital program portfolio.

As discussed previously, projects follow a two-stage estimating process. The first stage is to develop the scope with the assistance of the Engineering team, and produce a high-level cost estimate, as well as technical details related to the scope of work. After this milestone is achieved, the scope is frozen and, the second stage of the estimating process commences. Prior to inclusion in a regulatory application, and to inform the OEB of planned net capital expenditures and in-service addition targets, all projects should have cleared the first stage gate. As shown in the graphs below, the company is moving towards, but has not yet fully reach this desired state.

As a result of the improved readiness of the capital work program, there is increased confidence in the overall capital expenditures and in-service additions. As of May 1, 2016, 89% of the 2017 and 67% of the 2018 test work program's gross capital expenditures have passed the Budgetary Estimate stage gate (see Figure 2). This is a significant improvement over past years and provides an increased level of technical and financial assurance that informs the transmission capital expenditures and in Hydro One's ability to accomplish the overall work program.

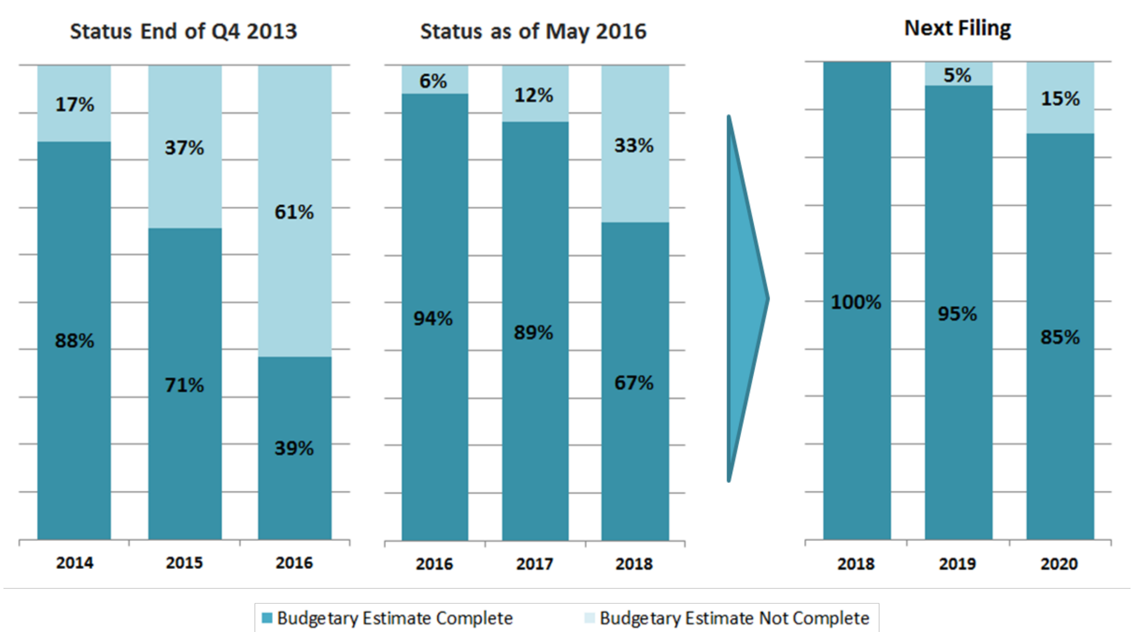

Figure 2: Current and Future State of Work Readiness

6. PRODUCTIVITY AND EFFICIENCY IMPROVEMENTS, PROJECT EXECUTION

A number of continuous improvement initiatives have been undertaken in this area and are outlined in the following sections.

6.1 Enhanced Delivery and Contract Models

The term '"delivery model" refers to the staffing model by which a project is executed and completed – e.g. entirely by internal staff, or in partnership with a third-party. Existing delivery models are being evaluated to determine how to achieve optimal business outcomes, including Hydro One's ability to accomplish work; the acceleration of projects into the execution phase; and flexibility in how work is implemented. Hydro One is also evaluating contract models used with third-party construction partners to determine if evolutions may result in increased cost efficiencies for rate payers (i.e. a mix of target price and fixed-price contract models.)

Hydro One believes that it has a highly flexible construction workforce that can meet the demands of a variety of work programs. Although the direct hire casual building trades workforce is scalable, there is a practical limit to its size defined by the volume of work that can be safely and efficiently planned and managed by internal staff. The work contracted out is completed using a combination of internal resources, engineering subcontracts, construction contracts or arrangements contracted on a fixed-price basis. Hydro One will continue supplementing internal resources with an external work force to execute the work program.

While maintaining and improving the current outsourcing strategy for greenfield station investments, the company will look to increase its outsourcing capacity to align with the growing work program. While development and station sustainment work have been successfully achieved using existing delivery models, the majority of the transmission capital work program increases in the test years are for overhead lines component refurbishment and replacement projects. Hydro One will believes it can effectively and efficiently outsource this work in order to achieve the growing work program. In the fall of 2016 Hydro One will be tendering a request for proposal (RFP) to identify construction partners who are experts in line refurbishment to create a list of vendors of record to expedite the RFP process to outsource projects. This will allow Hydro One to determine best practices and align standard approaches.

External resources are not only used by the construction team, but by groups such as engineering as well. By leveraging an external complement for engineering work, Engineering can create a pipeline of construction-ready projects to ensure that the work program is full achieved, and in a timely fashion. This partnership with a few key firms has allowed Hydro One to increase its opportunity for strategic feedback and align on processes and standards and establish a robust quality assurance process for engineering deliverables.

6.2 Quality Assurance/Quality Control Approach

Hydro One is introducing an improved end-to-end quality assurance & quality control program to ensure that work that delivered using external and internal delivery models is of a sufficient quality standard to ensure reliable, compliant and cost effective design, construction and commissioning activities. The program improvements will occur in two stages starting with work that is delivered externally and then for work that is delivered internally. The first phase will enhance the already established quality assurance practices to monitor the quality of construction. Subsequent efforts will include a review of current technology will also take place to identify opportunities for increased efficiency, accuracy and speed to capture and document the information.

6.3 Field Execution Efficiency

The benefits of introducing upstream efficiencies in the Project Definition Phase as well as the evolution of the company's delivery model strategy will result in tangible downstream improvements as field workforce productivity will benefit from improved project planning, engineered drawing timeliness, material delivery certainty and outage and staging plan optimisation. Although efficiency initiatives relating to downstream work practices are being considered, the current focus is on upstream processes, as these are foundational to support any significant changes in the field.

6.4 Project Closure Process and Lessons Learned

A formalized project closure process has been established with all key stakeholders, from the Project Definition and Execution, to ensure there is a feedback loop to enable continuous improvement. The closure process includes:

- Site inspection to confirm that the project has met all sponsor, customer and stakeholder requirements;
- Comparison of the project's estimated versus actual cost and a discussion of the differences;
- Verification that all deliverables have been met and accepted;
- Discussion of the significant changes in the project plan and the resulting impacts;
- Review of the contractor performance to the standard of the agreement (if applicable);
- Recommendations arising from the lessons learned during the project;

- Documentation of the issues and reasoning for deviations and the associated corrective actions taken; and
- Documentation of all lessons learned using the Hydro One knowledge management system, assignment of actions, and follow through on completion and communication to all relevant parties.

7. PRODUCTIVITY AND EFFICIENCY IMPROVEMENTS, GOVERNANCE

A number of continuous improvement initiatives have been undertaken in this area and are outlined in the following sections.

7.1 Organization Re-Alignment

Several organizational re-alignments have occurred to improve lateral integration throughout the capital project process, providing increased visibility for the management team to identify potential efficiencies. For example, Engineering resources have been consolidated into a single division to contribute to the overall efficiency of the stage gate process, allowing the Company to build engineering teams comprised of all disciplines that take an investment from the conceptual stage through to the completion of production engineering.

Another change involves the reallocation of Project Management resources to provide optimal support for projects. Project Managers and Project Schedulers, for example, have been re-assigned to projects based on geographical zones rather than project magnitude and complexity. Aligning investments and staff geographically to form multi-disciplinary teams accountable for the success of a project promotes a better understanding of the complexities associated with geographic challenges such as construction resource deployment and outage planning.

7.2 Portfolio Management

7.2.1 Capital Budget

As recommended in the Transmission Total Cost Benchmarking Study, Hydro One is working to formalise a rolling two-year capital budget and project portfolio with a reporting framework that includes parameters, authorizations and associated key performance indicators to promote continuous improvement. This will provide the flexibility needed to reschedule projects within a two-year rolling window and will ensure Hydro One is set up to achieve planned annual investments and meet future commitments.

7.2.2 Project Controls

An improvement initiative is underway to enhance the tool suite and processes for the Project Controls office to improve risk management, estimating, scheduling, project change management and reporting capabilities. The benefit will be improved accuracy in project forecasts and will further facilitate earned value reporting. The project controls initiative will include implementation of improved processes to strengthen rules and governance, the streamlining of the work breakdown structure, improving database maintenance, and encourage greater alignment with outage planning. It will also include a review of the organizational structure and effectiveness to ensure it is providing the level of support to project management.

Hydro One has selected a work program management partner to support the transition to these new improved tools and processes, assist in building the future state skill set, and help to manage any additional work program volume.

7.2.3 Improved In-Service additions Forecasting

A better connection has been established between capital expenditures and in-service additions across the project delivery organizations, allowing Hydro One project managers to forecast in-service additions more accurately. The Company is now also forecasting multi-year in-service additions, and has increased the practice of reporting partial in-servicing to optimize portfolio management resulting in minimized interest costs for assets under construction. Alignment of Project Delivery Managers with Area Construction Managers to perform monthly portfolio reviews of forecasted in-service additions has brought more rigor and control to the forecasting approach. On a quarterly basis the forecasting window expands to a multi-year window of gross cost and in-service additions.

7.2.4 Contingency

Hydro One is developing the tools necessary to analyze and manage contingency dollars at a portfolio level. Senior management discretion will determine the size of the contingency pool available to line managers and the establishment of a management reserve to enable strategic decision making. A more rigorous analysis of investment risks in the planning and scoping stages will ensure that an appropriate level of risk dollars is assigned for each capital project during the project definition phase. A consistent model will be established to forecast the use of contingency funds tied to specific risk of occurrence and a new change management system that requires higher level of approval and justification for the draw-down of contingency dollars. The release of a contingency fund at a project level will enable the availability of funding to develop other projects and aid in using the Capital investment budget to the fullest extent in a cost effective manner.

8. SAFETY INITIATIVES

The Operations team continually launches safety-related improvement initiatives. Continuous improvement in this area reflects the value the corporate culture places on safety. As shown in Figure 3, these initiatives have resulted in a steady decrease to the recordable injury frequency per construction hours worked at the same time that the overall work program has grown substantially. Also of positive note is that the general severity of incidents has consistently decreased over recent years, with reductions in the most severe incidents classified as high maximum reasonable potential for harm (high MRPH).

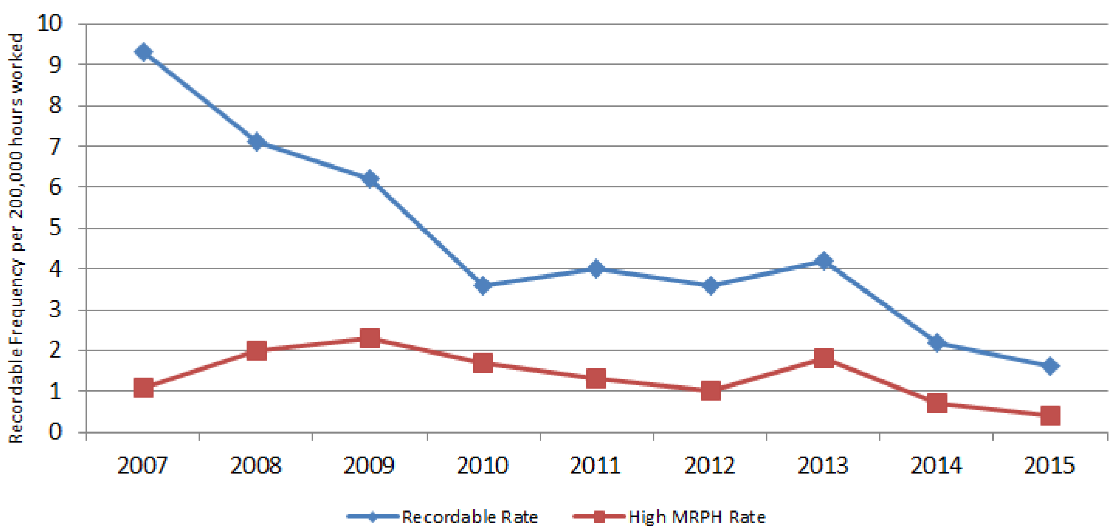

Figure 3: Recordable Injury Frequency per 200,000 Construction hours worked

In 2014 the company increased the complement of field business clerks to alleviate the amount of administrative work placed on the supervisors in the field. This initiative allows supervisors to provide greater oversight to their employees to ensure work is being conducted in a safe manner. A time study conducted in the summer of 2015 demonstrated that field supervisors are now spending 70% of their time on field supervision, up from 50%. This has been a significant factor in the improved safety record.

In 2015, the number of safety roll-outs to the field crews was increased from one to two. The safety roll-outs allow senior management to reinforce the company's commitment to safety and ensure that corporate targets and goals are communicated consistently. A fall session was added to allow staff to refocus on safety, bond with their peers, share experiences and learn from each other.

Hydro One has made improvements to the job planning function with the overall goal of improving engagement at the working level. Frequent tailboard sessions at the start of the day and after breaks serve to refocus field staff on critical hazards and reinforce safe and effective work practices. The use of open-ended questions is encouraged to generate good discussion and to ensure that everyone is heard. Crews participate in warm-up/stretch session during the course of the day as needed to reduce the occurrence of musculoskeletal injuries. The Company is well on its way to achieving its goal of zero workplace injuries, and safety initiatives will continue to be added to ensure this target is reached.

9. SUMMARY

Hydro One's Transmission Capital Work Execution Strategy has been able to demonstrate that it can accomplish a very large work program, while maintaining the needed flexibility to accommodate any required adjustments in that capital work plan due to changing priorities, project challenges and emergent investments. The improvement initiatives discussed in this exhibit have been carefully selected to ensure that the company can accommodate an increasing work program in a cost-effective, safe and reliable manner. The transmission capital work execution strategy will result in greater effectiveness throughout the stage-gate process and increased accuracy in forecasting work and timelines. A continued focus on the business objectives of the transmission system plan including safety, quality, efficiency, and meeting customer commitments will ensure Hydro One's success in accomplishing its capital work program.