Hydro One Remote Communities Inc.

Distribution System Plan

2018 Cost of Service Application

Historical Period: 2013 to 2017

Forecast Period: 2018 to 2022

June 21, 2017

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1 Introduction

Hydro One Remote Communities Inc. ("**Remotes**") has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB**'s") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated March 28, 2013 (the "**Filing Requirements**") as part of its 4th Generation IR Application based on a 2018 forward test-year cost of service review ("**the Application**").

1.1 Objectives & Scope of Work

Remotes' DSP has been prepared to support the four key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("**RRFE**"):

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

1.2 Outline of Report

This DSP has been organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements included in brackets for each heading.

The report contains four sections, including this introductory section as Section 1. Section 2 provides a high-level overview of the DSP including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of Remotes' asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of Remotes' capital expenditure plan including an overview of the capital expenditure planning process, an assessment of the system capability for Renewable Energy Generation ("**REG**"), and justification of material projects.

1.3 Background & Drivers

Remotes' capital investments over the planning period have been aligned to the four categories of system access, system renewal, system service, and general plant. Table 1-1 summarizes Remotes' drivers for each investment category over the forecast period.

Table 1-1: Remotes' Investment Drivers over the Forecast Period

Investment Category	Drivers	Projects / Activities
System access	Customer service requests	New customer connections and service upgrades Fixed price layouts Service cancellations
System renewal	Asset failure	Damage claims Defective meter replacements
	Assets at the end of their service life due to failure risk	Small external demand requests Distribution system improvements Generator replacements Generator overhauls Diesel plant civil improvements Day and bulk fuel tank replacements
System service	System capacity	Generator upgrades
	System reliability and operational efficiency	Supervisory Control and Data Acquisition ("**SCADA**") and Programmable Logic Controller ("**PLC**") upgrades
General plant	Non-system physical plant	Housing improvements Storage buildings and miscellaneous civil projects Minor fixed assets

System access investments are modifications to Remotes' distribution system (including asset relocations) that Remotes performs to provide customers with access to electricity services via the distribution system.

System renewal investments involve replacing and/or refurbishing system assets to extend the service life of the assets and thereby maintain the ability of Remotes' distribution system and generation fleet to provide customers with electricity services at reasonable rates.

System service investments are modifications to Remotes' distribution system and generation assets to ensure that the system continues to meet Remotes' operational objectives, while addressing anticipated future customer electricity service requirements.

General plant investments are modifications, replacements, or additions to Remotes' assets that are not part of its distribution or generation system, including land and buildings, tools and equipment, rolling stock, Information Technology ("**IT**") equipment, and software used to support day-to-day business and operations activities.

1.4 Description of the Utility Company

Remotes is an integrated generation and distribution company licensed to generate and distribute electricity within 21 isolated communities in Northern Ontario. Remotes is entirely debt-financed and operates as a break-even company with no return on equity.

Remotes is driven by its corporate vision, mission, and business values. Together, they provide the basis to deliver on targeted performance objectives.

Figure 1-1: Remotes' Corporate Vision, Mission, and Values

Corporate Vision: "We will be the leading electrical utility and a trusted partner to remote communities in Ontario's North."

Corporate Mission: "We supply safe, reliable and affordable electricity to remote communities by focussing on continuous improvement, operational excellence and outstanding customer service."

Corporate Values:

- Employee and public safety;
- Customers and community relationships;
- Environmental sustainability;
- Business integrity;
- Teamwork;
- Actively engaged employees;
- Operational excellence;
- Innovative thinking; and
- Continuous improvement.

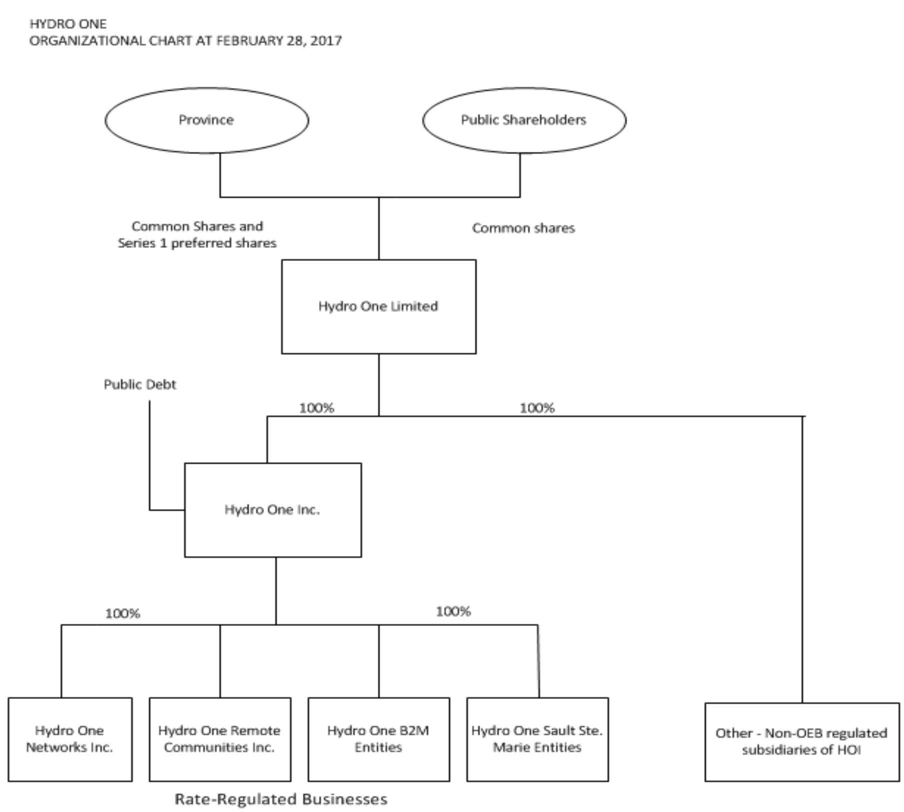
Remotes functions in a unique environment. Extremely low customer densities, a harsh climate, logistical challenges related to transportation, the absence of an integrated transmission system, and complex funding arrangements with third parties set Remotes apart from other Ontario distributors.

The communities served by Remotes are isolated and scattered across the Far North of Ontario. Thirteen communities are not accessible by year-round road and can be reached only by aircraft, winter roads or, in the case of one community, by barge, air, or winter road. The size and isolation of Remotes' service territory also means that the transportation and accommodation of staff, fuel, and equipment are key drivers of its costs. The company's reliance on winter roads for access to communities is also a major driver of work scheduling and completion activities, as scheduled projects may require deferral where winter roads cannot be constructed due to weather conditions, leading to project deferrals and the ensuing higher fuel and maintenance expenditures.

Remotes inherited Ontario Hydro's obligations to provide electricity to off-grid communities, which obligations were originally negotiated with the federal and provincial governments. Under these arrangements, the federal and provincial governments funded the original capital installation of facilities. In First Nation communities, the arrangements with the federal government ("the **Agreements**"), through Indigenous and Northern Affairs Canada ("**INAC**") remain in place. The Agreements specify that Remotes is responsible for funding the ongoing operation and maintenance of the system and that INAC is responsible for funding capital related to system expansions and capital upgrades. In the 1990s, INAC devolved responsibility for community infrastructure to First Nation communities. INAC now transfers funding to First Nations, who are responsible for administering most of the INAC's program funds. Therefore, Remotes' asset planning is a three-party process involving First Nation Band Councils, INAC, and Remotes. The timing and amount of funds available from INAC for funding upgrades is limited by overall funding constraints. Funding for new stations and larger engines must compete with other departmental priorities and may not be available in the year investment is required.

Remotes is wholly-owned by Hydro One Inc., which also owns 100% of Hydro One Networks Inc. Hydro One Inc. is, in turn, 100% owned by Hydro One Limited, whose ownership is split between public shareholders (through a Toronto Stock Exchange listing) and the Province of Ontario. As a subsidiary of Hydro One Inc., Remotes has access to operational, legal, regulatory, and financial expertise in the energy industry, and to leading technology and world-class expertise in innovation, engineering and design. As a small business, Remotes understands its customers and works closely with them.

Figure 1-2: Hydro One Inc. Corporate Structure



Remotes is licensed to provide both generation and distribution services outside of the competitive electricity market through its licences ED-2003-0037 and EG-2003-0138, which identify its service territory and generation facilities. Remotes is obligated to maintain system integrity and to comply with codes, legislation, regulations, and market rules. However, Remotes is exempt from certain requirements that are not applicable to its operations due to the unique nature of its business.

1.4.1 Service Area including Map

Remotes' service territory is spread out across Northern Ontario, as depicted in Figure 1-3. Remotes is currently licensed to generate and distribute within 21 isolated communities. These communities are shown in red in Figure 1-3 Collins and Whitesand, which are served via the Armstrong distribution system. Fifteen of these communities are First Nation communities, and thirteen are air access only.

Figure 1-3: Map of Remotes Service Territory

Three additional communities are anticipated to be added to Remotes' service area in the years 2018 to 2020: Cat Lake, Pikangikum, and Wunnumin Lake.

Table 1-2: List of Communities Serviced by Remotes

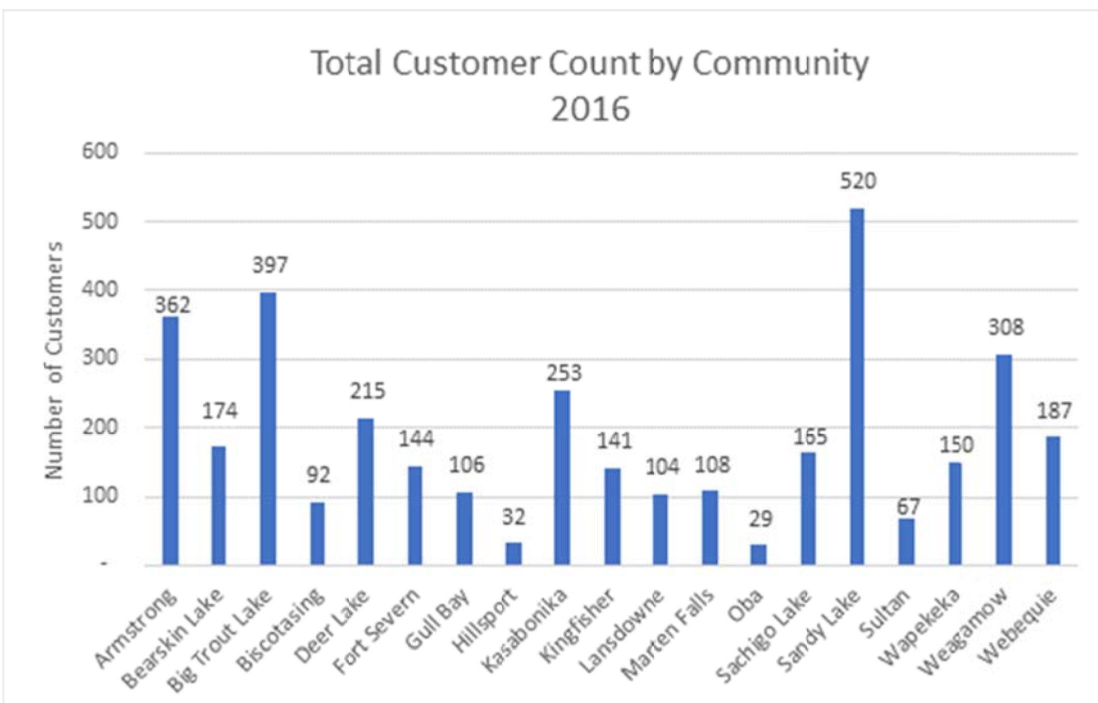
Presently Served by Remotes		
Armstrong	Gull Bay	Sachigo Lake
Bearskin Lake	Hillsport	Sandy Lake
Big Trout Lake	Kasabonika Lake	Sultan
Biscotasing	Kingfisher Lake	Wapekeka
Collins*	Lansdowne House	Weagamow
Deer Lake	Marten Falls	Webequie
Fort Severn	Oba	Whitesand*
Anticipated to be Served by Remotes in the Near Term		
Cat Lake (2018)	Pikangikum (2019)	Wunnumin (2020)

**Energy for Collins and Whitesand is provided from Armstrong*

1.4.2 Electricity Distribution

Remotes' 19 self-sufficient, stand-alone generation/distribution systems serve a total of 3,554 customers based on the 2016 year-end count. Figure 1-4 depicts the customer counts across those 19 systems. Customers in Collins and Whitesand are included in the Armstrong count.

Figure 1-4: Customer Count by Community in 2016



These communities are expected to grow slightly over the forecast period, as shown in Table 1-3. The largest anticipated customer increase is due to the three new communities which are expected to join Remotes' service area over the forecast period: Cat Lake (2018), Pikangikum (2019) and Wunnumin Lake (2020).

Table 1-3: Forecast Customer Counts in the Years 2017 to 2022 by Community

Year	2017	2018	2019	2020	2021	2022
Armstrong	366	367	370	372	374	377
Bearskin Lake	180	182	184	186	189	191
Big Trout Lake	403	405	409	413	417	421
Biscotasing	94	95	96	96	97	98
Cat Lake	-	110	114	118	122	126
Deer Lake	224	225	226	226	228	228
Fort Severn	149	151	153	156	158	160
Gull Bay	107	107	108	108	108	109
Hillsport	32	33	33	33	34	34
Kasabonika	264	267	274	280	286	293
Kingfisher	144	144	144	144	144	144
Lansdowne	105	106	106	106	107	107
Marten Falls	113	116	121	125	131	135
Oba	30	31	31	31	32	32
Pikangikum	-	-	531	533	538	541
Sachigo Lake	170	171	172	172	174	175
Sandy Lake	525	527	531	533	538	541
Sultan	68	68	69	69	70	71
Wapekeka	151	151	151	151	151	151
Weagamow	311	312	315	319	322	324
Webequie	191	194	198	203	207	211
Wunnumin	-	-	-	175	178	180
Total	**3,627**	**3,762**	**4,336**	**4,549**	**4,605**	**4,649**

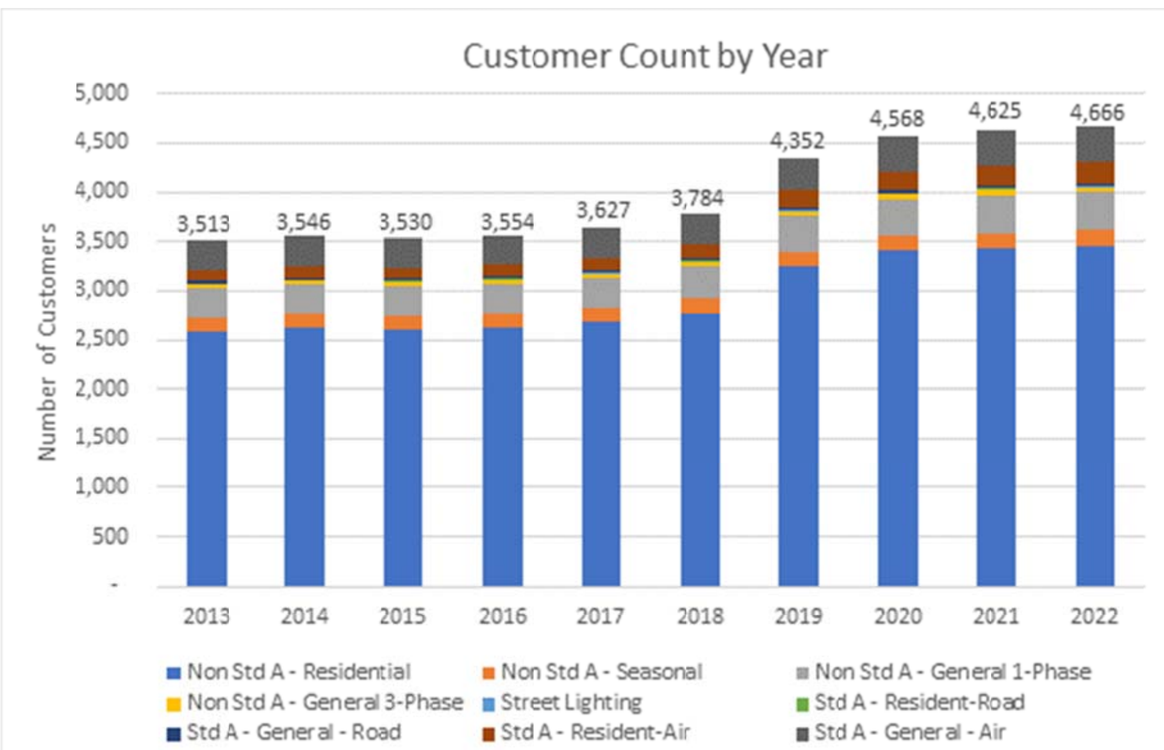
O. Reg. 442/01, a provincial regulation under the *Ontario Energy Board Act, 1998*, sets out two broad categories of customers that Remotes serves: customers who receive Rural or Remote Rate Protection ("**RRRP**") (which includes residential, General Service, and street lighting "**Non-Standard A**" customers); and customers occupying government premises, defined as customers who receive direct or indirect funding from government ("**Standard A**" customers). Standard A customers include the Ontario Ministry of Transportation, Health Canada, and INAC. Customer classes in this category are defined depending on the access to the community (air or road) and the type of service (residential or General Service). Non-Standard A customers are all other residents and businesses who received subsidized rates through the RRRP. The Non-Standard A customers are grouped by the type of service: residential or General Service. Residential customer classes are divided into seasonal and year-round, while General Service customer classes are divided into single-phase and three-phase service. Table 1-4 summarizes the definitions of the customer classes served by Remotes.

Table 1-4: Summary of Customer Classes Served by Remotes

Customer Type	Definition	Customer Classes
Standard A	Government-funded (e.g. Health Canada, INAC)	Residential – air access Residential – road access General Service – air access General Service – road access
Non-Standard A	Non-government-funded	Residential year-round Residential seasonal General Service single-phase General Service three-phase
Street lighting	Community-owned public lighting	Street lighting

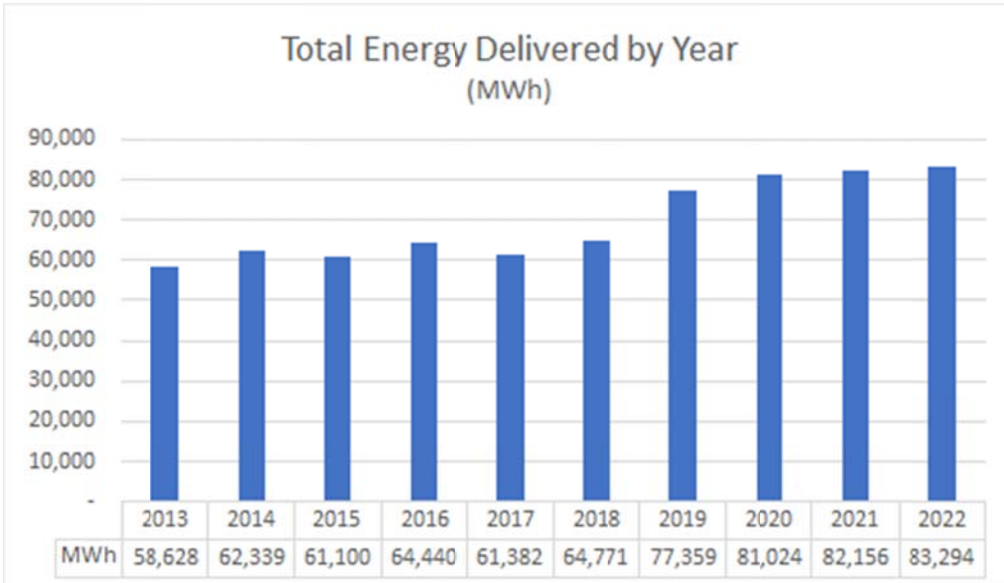
As depicted in Figure 1-5, the customer base has been stable over the historical period, but is expected to grow in the next five years with the addition of the three new communities. The largest step increase is projected for 2019 when Remotes begins serving Pikangikum.

Figure 1-5: Year-end (2013-2016) and Forecast (2017-2022) Customer Counts



The total annual amount of energy delivered remained generally consistent over the historical period, as shown in Figure 1-6, but is expected to increase over the forecast period as new communities are added.

Figure 1-6: Total Annual MWh Delivered



1.4.3 Electricity Generation

Remotes generates electricity to meet its obligations under Section 29 of the *Electricity Act, 1998*, since the communities it serves are not connected to Ontario's bulk electricity system. The main source of electricity supplied to the communities are 57 diesel-fuelled generators with a combined capacity of 31,000 kW. Remotes also owns wind turbine generators and hydroelectric generating facilities. There are wind turbines at four sites: three in Kasabonika with a capacity of 10 kW each, and one in Big Trout Lake with a capacity of 60 kW. There are two hydroelectric generating facilities in Deer Lake sized 225 kW each and one in Sultan with 150 kW capacity.

1.4.4 Energy Conservation and Demand Management

Remotes' energy Conservation and Demand Management ("**CDM**") program aims to reduce the kWh usage in the communities as a means of managing system costs and improving the affordability of electricity bills for the company's customers. To assist Remotes in the development and delivery of CDM programs the company entered into several partnerships with the participating First Nation communities, Northwest Company, Elephant Thoughts Energy Conservation Youth Camps, and MGM Electrical Commercial Lighting Retrofit Program. The scope, nature and impact of the resulting programs are discussed below. Remotes program is supplemented by programs aimed at First Nation communities managed by the Ontario Power Authority ("OPA") [now the Independent Electricity System Operator ("**IESO**")] and federal programs.

1.4.4.1 Programs over the Historical Period

The following CDM programs were created and implemented over the past five years. Each program was promoted to customers by Remotes and through community representatives.

Community Conservation Pilot Program

Since 2006, Remotes offered an array of free products and financial support to the communities, enabling them to hire local Energy Conservation Officers to act as a key liaison, or community spokesperson, and installation support. The program was offered in partnership with local Band Councils and provided hands-on practical training as well as community information sessions. The program has been discontinued due to difficulty in engaging Band Councils as partners and in hiring, training, and retaining local resources to carry out the program.

Mail in Rebate Program

This program is application-based and presents a mail-back rebate on Energy Star and other energy efficient products when purchased.

Energy Conservation Youth Camps

The primary purpose of this CDM program was to engage community youth aged seven to twelve to learn about energy and water conservation. Camps were held over multiple days and delivered by an external provider responsible for developing a hands-on, age-appropriate curriculum. The program was delivered in four communities, with the delivery costs being shared with the participating communities. The program was discontinued due to limited community interest.

Community Conservation Competitions

This program created friendly competition among community members to drive a conscious effect to conserve electricity. Participants were eligible to win cash prizes for saving the most electricity based on their historic data. This program was implemented in one community over a few months. Although the participating community decreased its consumption by 12% during the competition, longer-term results were not sustained and the program is no longer offered.

Commercial Lighting Retrofit

Designed to assist commercial and Standard A customers reduce their energy consumption, this program assists customers with upgrades to their lighting systems. Remotes facilitates detailed lighting audits and upgrade cost estimations by a third-party company. Remotes does not have any industrial customers and has very few commercial and institutional customers, making the uptake of this program limited. Remotes continues to market this program.

Holiday Lighting Exchange

This program was offered on a community-by-community basis. The intent of this program was to switch out old incandescent holiday lighting with LED options. As lighting exchanges were offered in all the First Nation communities and have been completed by interested customers, opportunities for further deployment of holiday lights are limited.

Rebate–Fridge Roundup

This program was offered to all communities with Northern Stores in partnership with Northwest Company. The program offered free pickup and disposal of old refrigerators and a rebate if a participant purchased a new Energy Star refrigerator. Only two communities signed up, with only a handful of customers participating. Based on the limited uptake, the program is no longer marketed.

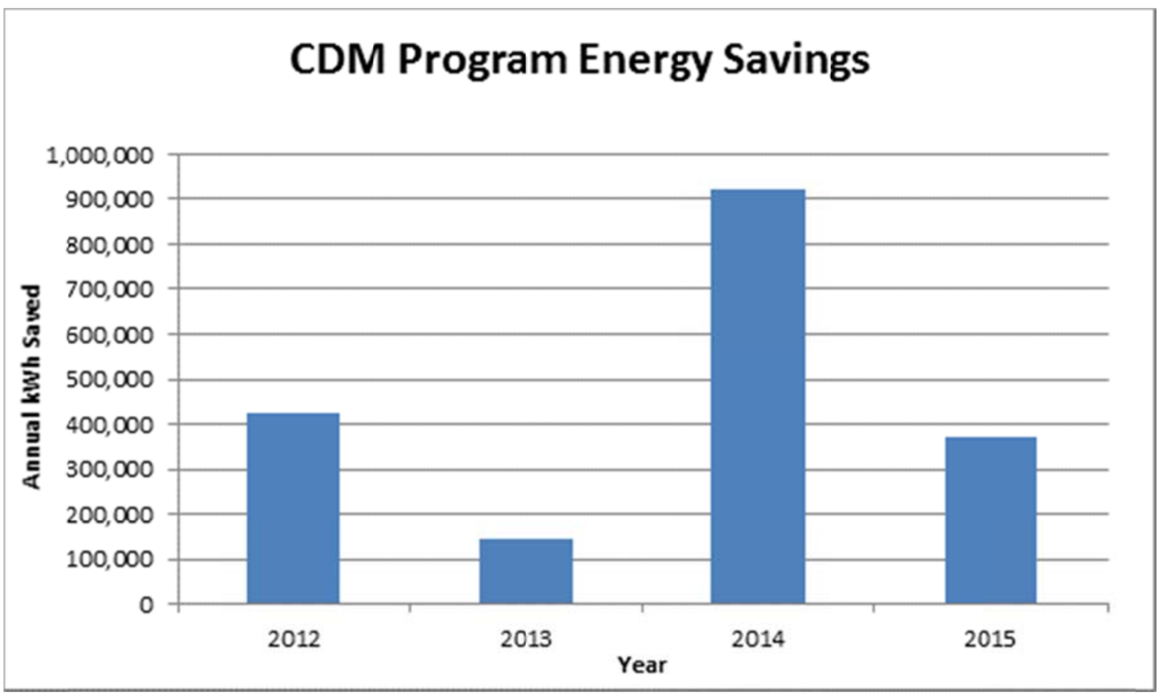
Street Lighting Retrofit

This program targets communities with existing streetlight systems and provides financial assistance to retrofit existing inefficient lamps to LED replacements. It is available to each of the seven communities with streetlight systems. To date, only one has taken advantage of the program. Remotes will continue making this program accessible for the remaining six communities until the upgrades are complete.

1.4.4.2 Achievements

Figure 1-7 depicts the combined energy savings of Remotes' CDM program for the years 2012 to 2015. The amount of kWh savings is directly related to the amount of participation at the community level and the amount of product installed.

Figure 1-7: CDM Program Energy Savings, 2012-2015



Externally-funded programs impacted program uptake over the historical period. Both the federal government and the IESO offered similar programs in the communities.

1.4.4.3 Challenges and Future Outlooks

There are numerous challenges affecting the execution of Remotes' CDM programs. First, the isolation of the communities means that there are limited opportunities to exchange large items such as refrigerators, since they must be transported out of the communities over winter roads. The OPA (now the IESO) and the federal government both offered communities opportunities to create community energy plans. From those plans, Band Councils expressed interest primarily in renewable energy development and in grid connection. In particular, renewable energy fits well with community priorities for environmental protection and as a means of creating local business opportunities. Interest from Band Councils on partnering in CDM initiatives was comparatively limited. Without strong support for the CDM programs from Band Councils, recruiting, training, and keeping local resources in place is challenging.

Remotes' customer base consists primarily of residential customers and lacks large commercial and industrial segments that provide material CDM program attainments for the rest of the province. Given the small number of customers and funding for similar programs from CDM, there are limited opportunities for savings.

Remotes is not included as part of the province-wide Conservation First Framework and, therefore, has not been allocated a budget or program achievement targets under the current framework.

Considering the above-noted factors, Remotes has allocated its resources in support of REG investments to better align itself with the preference of community leadership. Future CDM activities undertaken by Remotes will focus on community education and awareness, the kWh benefits of which cannot be readily attributed to specific measurable decreasing demand.

2 Distribution System Plan (5.2)

This section provides a high-level overview of the DSP including information on coordinated planning with third parties and performance measurement for continuous improvement.

2.1 Distribution System Plan Overview (5.2.1)

Remotes operates 19 isolated distribution systems in 21 communities in Northern Ontario. Remotes' service area will be expanding to include three additional communities. There are over 1,000 kilometres between the northernmost community, Fort Severn, and the southernmost community, Biscotasing. Thirteen of these communities are accessible by air only, meaning that Remotes' personnel, stationed in Thunder Bay, must fly to and from the communities when work is required. Given the extensive use of air transportation, cargo costs become an important consideration for the budget optimization efforts. The transportation of cargo is also an important planning consideration, as equipment and building materials cannot be purchased in the communities, can be too large to fly in regular cargo planes, and must therefore be trucked in over the six-week winter road season. If weather does not permit, winter roads may not be available to transport freight. Remotes keeps equipment and lodgings for its crews in each community to facilitate multiday project construction and maintenance activities and alleviate air transportation costs.

In the absence of a transmission system connection, Remotes is the generator and distributor for its customers. Cat Lake, anticipated to be added to Remotes' service area in 2018, is the only community connected to the transmission system. Much of the capital and system operations and maintenance ("**O&M**") expenditures is related to the upkeep and replacement of the diesel generator fleet. Remotes has a rigorous program to manage its generator fleet, including maintenance, overhauls, and replacements based on the number of operational hours ("**engine-hours**"). Diesel fuel is by far the single most significant cost for Remotes.

Planning for growth in Remotes' service territory is complex and somewhat unpredictable. Funding for growth-related capital is mainly a federal responsibility. INAC faces funding constraints and an overwhelming need for infrastructure in First Nations communities. The need for electricity infrastructure competes with requirements for schools, housing, water treatment plants, etc. The timing for funding approvals and the amount of funding available is uncertain and requires planning flexibility to accommodate growth within these communities. The federal government also has rules related to the timeframe in which the funding is spent and a project is completed. If funding is not spent within the federal government's time frame, the funding is returned to federal general revenues or deployed to another needed project. Consequently, funding levels and projects may be determined late in INAC's fiscal year and if funding becomes available, Remotes adjusts its planned work program to accommodate upgrade projects.

The provincial government plans to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes and seven are operated by Independent Power Authorities ("**IPA**s"). The provincial and federal governments have indicated that all the communities must be served by a licensed distribution company to connect to the grid. Five IPAs have requested service from

Remotes. Two of these IPA communities, Pikangikum and Wunnumin Lake, are planned to be included in Remotes' service territory over the forecast period. Although an Order-in-Council has been issued by the Minister of Energy, the Remote Community Connection Plan is still in draft form. Wataynikaneyap ("**Watay**") Power, the future owner and operator of the new transmission facilities, is commencing the development and approval process. An IESO-led study is considering the feasibility of leveraging Remotes' diesel generators for backup power supply once these communities are grid-connected.

In summary, these unique operating conditions are reflected in Remotes' DSP.

2.1.1 Key Elements of the DSP (5.2.1a)

To understand the key elements of Remotes' DSP, it is first important to understand the prospective business conditions driving the size and mix of capital investments required to achieve planning objectives over the forecast period. Capital investments are divided into three main categories of distribution, generation, and general plant. Each of these is discussed in a separate section below.

2.1.1.1 Distribution

Table 2-1 presents the distribution capital expenditures and system O&M costs for both the historical and forecast period. In accordance with the OEB requirements, the distribution capital expenditures are separated into three investment categories of system access, system renewal, and system service – although Remotes made no system service investments over the historical period and plans no such investments over the forecast period. General plant investments are described separately in Section 2.1.1.3.

Table 2-1: Historical and Forecast Capital Expenditures and System O&M - Distribution

Investment Category	**Historical ($'000)**					**Forecast ($'000)**				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
System Access										
Gross	597	605	800	534	872	912	1,065	1,121	1,143	1,166
Contributions & Removals	(474)	(574)	(757)	(464)	(872)	(912)	(1,065)	(1,121)	(1,143)	(1,166)
Net	123	31	42	70	-	-	-	-	-	-
System Renewal										
Gross	1,291	739	681	895	742	772	899	947	965	983
Contributions & Removals	(535)	(235)	(137)	(135)	(241)	(250)	(290)	(304)	(311)	(313)
Net	756	504	544	760	501	522	609	643	654	670
System Service										
Gross	0	0	0	0	0	0	0	0	0	0
Total Capital										
Gross	**1,889**	**1,344**	**1,481**	**1,428**	**1,614**	**1,684**	**1,964**	**2,068**	**2,108**	**2,149**
Contributions & Removals	**(1,010)**	**(809)**	**(895)**	**(599)**	**(1,113)**	**(1,162)**	**(1,355)**	**(1,425)**	**(1,454)**	**(1,479)**
Distribution Capital, Net	**879**	**535**	**586**	**830**	**501**	**522**	**609**	**643**	**654**	**670**
Distribution O&M	**4,981**	**4,105**	**3,260**	**3,908**	**4,197**	**4,393**	**5,055**	**5,567**	**5,671**	**5,496**
Total Spend, Distribution	**5,860**	**4,640**	**3,846**	**4,738**	**4,698**	**4,915**	**5,664**	**6,210**	**6,325**	**6,166**

2.1.1.1.1 System Access

System access investments are a small portion of Remotes' spending over the forecast period. The size and mix of investments in this category are largely determined by customer requests and other external factors. The work is 100% recoverable from the requesting parties, and includes service cancellations, fixed price layouts, new customer connections, and service upgrades. Service cancellations are initiated by customers to ensure that monthly billing ceases. Most cancellations are a result of house fires or customer requests to disconnect services that are no longer needed. Fixed price layouts are provided when requested by customers in a cost-effective manner while ensuring compliance with Remotes' Distribution Standards as required under *O. Reg. 22/04*, the electrical distribution safety regulation under the *Electricity Act, 1998*. New customer connections and service upgrades are also driven by customers seeking connection to the system where sufficient capacity is available.

2.1.1.1.2 System Renewal

A large portion of distribution capital investment in the system renewal category falls under Distribution System Improvements. Major distribution system capital improvements are made in one or two communities per year – depending on the size of the community – along with minor betterment projects in other communities. These betterments typically entail replacements of aging or defective poles, conductor restringing, and pole re-alignments based on the asset condition surveys in the community. Betterments and system upgrades are made to facilitate system reliability and joint-use of poles. New Viper switches are installed based on the power system reliability in the community, cold-load pickup, and operating experience. Viper switches allow on-site operator response as well as operating flexibility to limit the impact of lengthy outages to customers.

Other distribution system capital investment in the system renewal category includes Defective Meter Replacements, Minor Storm Damage Repair, Damage Claims, and Small External Demand Requests. Defective Meter Replacements and storm damage repairs mainly depend on severe weather occurrences, particularly lightning, wind, and ice storms. Damage claims work entails repairs to equipment resulting from damaged caused by members of the public.

Although the number of distribution assets under management by Remotes is expected to increase over the forecast period when the new communities are added to the service area, no major increase in distribution system renewal spending has been planned since INAC is funding upgrades to the distribution lines before they are transferred to Remotes. This will, however, affect the amount of O&M expenditures in the future to maintain this equipment. Increased metering costs have been budgeted based on the anticipated service area additions.

The planned increase in spending on these programs over the forecast period is modest.

2.1.1.1.3 System Service

There are currently no system service programs budgeted on the distribution side.

2.1.1.2 Generation

Table 2-2 depicts the generation capital expenditures and system O&M costs for both the historical and forecast period. The generation capital investments are divided into the system renewal and system service categories. Generation investments do not fall into the system access category, since it entails distribution system work to connect work to connect customers, such as metering and service layouts. General plant investments are described separately in Section 2.1.1.3.

Table 2-2: Historical and Forecast Capital Expenditures and System O&M - Generation

Investment Category	Historical ($'000)					Forecast ($'000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System Renewal										
Gross	3,651	4,064	1,172	2,659	1,795	1,788	2,847	3,582	3,994	2,426
Contributions & Removals	(250)	(449)	115	(224)	(67)	(144)	(211)	(213)	(204)	(205)
Net	3,401	3,615	1,288	2,434	1,728	1,644	2,636	3,369	3,791	2,221
System Service										
Gross	499	167	7,054	2,588	7,884	5,853	6,852	6,392	5,412	5,810
Contributions & Removals	(43)	(360)	(7,073)	(2,588)	(7,471)	(5,348)	(6,126)	(5,717)	(5,021)	(4,962)
Net	456	(193)	(19)	0	413	505	726	675	391	848
Total										
Gross	**4,150**	**4,231**	**8,226**	**5,247**	**9,679**	**7,641**	**9,699**	**9,974**	**9,406**	**8,236**
Contributions & Removals	**(293)**	**(809)**	**(6,957)**	**(2,813)**	**(7,538)**	**(5,492)**	**(6,337)**	**(5,930)**	**(5,225)**	**(5,167)**
Generation Capital, Net	**3,857**	**3,422**	**1,269**	**2,434**	**2,141**	**2,149**	**3,362**	**4,044**	**4,182**	**3,069**
Generation O&M	**11,811**	**13,120**	**11,982**	**12,883**	**15,168**	**15,496**	**15,786**	**16,737**	**17,024**	**17,315**
Total Spend, Generation	**15,668**	**16,542**	**13,251**	**15,317**	**17,309**	**17,645**	**19,148**	**20,781**	**21,206**	**20,384**

2.1.1.2.1 System Renewal

Generation system renewal spending for the management of Remotes' 57 generator units accounts for, on average, 60% of Remotes' budgeted net capital expenditures over the forecast period. Generation programs in the system renewal category are largely driven by condition of the units. The number of hours that an engine operates, not age, determines when a generator should be replaced or overhauled. Remotes performs this work in accordance with manufacturer's recommendations. Remotes also considers the maintenance history (reliability) of the unit, future capacity requirements and access to parts when making repair or replacement decisions. Generating station civil improvements are budgeted based the condition of the foundations and structures as determined through inspections. Day and bulk tank replacements are planned based on the need to replace end-of-life fuel tanks determined by condition and compliance.

2.1.1.2.2 System Service

Generation programs in the system service category make up a significant portion of Remotes' gross capital expenditures, but many of these projects are funded externally.

Generator upgrade projects are driven by capacity requirements and are 100% recoverable. SCADA and PLC programs are non-recoverable system service investments over the forecast period, which are driven by the requirement for improved plant data acquisition and control, generator asset management, and operator interaction through a modern Human-Machine Interface ("**HMI**").

2.1.1.3 General Plant

General plant investments are modifications, replacements, or additions to Remotes' assets that are not part of its distribution or generation system. Individual programs in the general plant category over the forecast period fall below the materiality threshold ($283,000). These investments include life extension of staff housing in each community, driven by the condition of the lodging. Investments into storage buildings and other miscellaneous civil projects are made based on the need to have a suitable location that is large enough to store and perform maintenance on large equipment such as backhoes and Radial Boom Derricks ("**RBD**s"). This need is partly due to the transportation issues that exist in the Remotes. Other investments into minor fixed assets are made to purchase items such as storage containers and snow buckets.

Table 2-3: Historical and Forecast Capital Expenditures – General Plant

Investment Category	Historical ($'000)					Forecast ($'000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
General Plant										
Gross	691	677	473	914	1,085	565	572	581	590	598
Contributions & Removals	0	0	0	0	0	0	0	0	0	0
Net	**691**	**677**	**473**	**914**	**1,085**	**565**	**572**	**581**	**590**	**598**

2.1.2 Anticipated Sources of Cost Savings (5.2.1b)

2.1.2.1 Historical Achievements

Remotes has introduced many programs over the past few years to improve efficiency, contain current costs, and mitigate future cost increases. Through prudent planning and DSP execution. Remotes will continue to realize cost savings over the forecast period.

Table 2-4 illustrates the anticipated cost savings delivered through these programs.

Table 2-4: Summary of Cost Savings 2017-2022

Cost Savings	Historical ($)				Forecast ($)					
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Winter Road Fuel Savings	1,144,998	3,516,961	1,170,388	496,576	570,783	570,783	570,783	570,783	570,783	570,783
First Nation Fuel Savings	407,642	347,572	177,023	658,264	643,151	643,151	643,151	643,151	643,151	643,151
Meter Reader Savings	758,819	873,007	952,415	1,370,443	1,370,857	1,374,653	1,379,422	1,384,341	1,388,536	1,393,624
Operator Savings	6,825,617	9,797,954	9,727,773	9,825,312	9,825,312	9,790,318	9,861,849	9,934,095	9,971,020	10,044,718
Webshare Savings	-	-	79,200	79,200	79,200	79,200	79,200	79,200	79,200	79,200
Total	**9,137,076**	**14,535,494**	**12,106,799**	**12,429,796**	**12,489,304**	**12,458,105**	**12,534,405**	**12,611,571**	**12,652,690**	**12,731,477**

Diesel fuel is Remotes' single largest cost component. Winter road fuel savings is the cost difference between trucking fuel in over winter roads compared to flying it in. Similarly, First Nation fuel savings is the cost difference between trucking fuel in over winter roads and storing it in First Nation tank farms compared to flying it in.

Meter reading and operator savings are differences in cost between contracting with a local person in the community and using workforce resources from Remotes. Usually, Remotes reads its own meters but contacts the First Nation band councils for local employment. Contracting with local resources offers job opportunities within economically disadvantaged communities.

Webshare savings result from accessing data such as 3D scans via Webshare instead of flying to the site for tasks such as preliminary design updates. The estimated value also includes productivity gains from a reduction in the time required to gather accurate information such as nameplate data.

In addition to these sources of cost savings that have been described and estimated over the forecast period, Remotes engages in numerous initiatives to reduce costs that are less readily quantifiable.

As the condition of diesel generators deteriorate, they become less fuel-efficient and, therefore, costlier to operate. Capital investments to replace or overhaul generators mitigate the loss of efficiency thereby reducing the fuel costs to operate the generator. Generator upgrades, although driven by capacity constraints, have the added efficiency cost benefit of replacing an older generator. Due to the continuous improvement of generator technology, new diesel generators installed in the field have higher nameplate efficiency than the older models they replace, amplifying the fuel savings. Remotes uses automatic generator dispatch to optimize the efficiency of its fuel consumption. Planned replacements, overhauls, and upgrades reduce the risk cost associated with owning and operating the generator.

Good project scheduling, planning and execution contribute to cost savings in terms of avoided costs. This includes project scoping to bundle assets into a single project for optimization of resource mobilization and demobilization. This approach reduces the cost of air transportation of personnel and also ensures crews perform all known work required when they visit a remote community.

Planned replacements of distribution assets through the Distribution System Improvements program are a cost-effective way to manage these assets. The betterment of one community per year is planned to focus Remotes' efforts and reduce the number of flights. This program focuses on the worst sections of feeders identified during inspections. This proactive work reduces future trouble call costs increasing the system's resiliency to storms through pole replacements, conductor restringing, and pole realignments.

SCADA and PLC upgrades planned over the forecast period will result in improved system data acquisition and control with an HMI at several generating stations. The improved SCADA system will reduce the number of trips required for troubleshooting when the alarm can be cleared remotely. The new HMI will reduce the operator response time though improved interaction and alarm handling. The data collected by these new systems are expected to be used to drive asset management decisions in the future and to better monitor the condition of the diesel generator fleet.

As part of the generator replacements and upgrades, old generators are brought back from the site and sent out for investment recovery. Removed generators can be used as spares or for spare parts to derive the most value out of the retired asset.

Generator upgrade projects factor in the available transformation capacity of the Generator Step-Up transformers ("**GSU**s"). If the existing GSU can provide adequate supply for the community and is in serviceable condition, it remains in service. This serves to reduce the capital cost requirement of the project.

New generating station construction incorporates the *Remotes Station Design Guidelines*. By following standardized designs, Remotes reduces the design, engineering, and construction costs of these projects. Since these projects do not affect the rate base, these cost savings are passed on directly to INAC. Furthermore, the use of standardized generating station designs allows Remotes' crews to follow existing work practices and manuals for the upkeep of the stations, improving operational efficiency.

New connections and fixed price layouts are planned using standardized designs that meet the requirements of *O. Reg. 22/04*. This decreases the engineering and design costs of projects, while still providing high-quality layouts. Since these programs are customer-funded, these cost savings are passed directly to customers.

Additional cost savings are achieved through the sharing of software and IT systems with Remotes' parent company, Hydro One Inc. The cost sharing is defined in Service Level Agreements between Remotes and Hydro One Inc.

2.1.2.2 Investments in Efficiency

Over the past five years, Remotes has invested in civil improvements such as walkways and garages to reduce time that crews spend shovelling snow on sites, digging out hydro trucks from heavy snow, reducing the time to respond to emergencies, and/or commencing work in the station. Investments in RBDs have improved crews' ability to perform line work in the communities. However, the distance and time required to get to and from site makes these efficiency improvements difficult to quantify. Remotes has focussed on improvements to its procurement planning to ensure that materials can be transported to site over winter road and jobs executed when planned. With this DSP, Remotes is investing in the building blocks necessary to modernize an off-grid electricity system. Besides maintaining the fuel efficiency from the original PLC-SCADA system, the new SCADA system is expected to improve Remotes' ability to diagnose the cause of failures from the Thunder Bay office. Along with the improved 3-D drawings of the plant, this will help to ensure that field staff have the materials required to fix the failure when they get to site. It may also reduce the time required for field staff to troubleshoot on site, or improve the ability for operators to respond to outages. Other Ontario utilities have uncovered ways to use improved data from their assets to reduce trouble costs, and Remotes expects to leverage modern communication systems to create similar impacts on its business.

Remotes has experience with the impact of high penetration hydro-electric power in Sultan, where the renewable resource can fully power the community during the summer months reducing engine hours and required engine maintenance. Solar power is a new technology in a Canadian off-grid where limited solar resource, small scale, expensive installation costs and distribution system penetration have delayed implementation. This is the technology supported by the federal and provincial governments. Solar-battery installations may have an impact on winter peak, but is more a more promising technology for the potential to reduce engine hours during the summer months. With limited operational experience with this technology, Remotes is not yet able to estimate the impact on engine hours, but the potential is there for the two planned solar projects in Fort Severn and Gull Bay.

By participating in, and advocating for the Watay project, Remotes is working toward a large fuel cost reduction, much lower emissions and reduced capital and OM&A expenditures on diesel plants, and a more flexible power solution for its customers.

2.1.3 Period Covered by DSP (5.2.1c)

This DSP covers a historical period of 2013 to 2016, 2017 is the Bridge Year. The forecast period is 2018 to 2022, where 2018 is the forward Test Year.

2.1.4 Vintage of the Information (5.2.1d)

The information contained within this DSP should be considered "current" as of January 2, 2017.

2.1.5 Important Changes to Asset Management Processes (5.2.1e)

This is Remotes' first DSP filing; therefore, there are no changes to its asset management process compared to a previous DSP filing. Remotes' previous Cost of Service filing did not include an Asset Management Plan.

2.1.6 DSP Contingencies (5.2.1f)

The execution of Remotes' investment programs is contingent upon various external factors. The most important of these factors are external funding requirements (through INAC), nature and volume of customer-initiated work, transportation requirements, resource availability, and regional electricity infrastructure requirements.

External Funding Considerations

INAC provides funding for programs, services and initiatives to First Nation, Inuit and Northern communities, governments and individuals, as well as to Aboriginal and Métis organizations. Under the terms of the electrification agreements, INAC is responsible for funding generation and distribution capital upgrades associated with load growth in First Nation communities served by Remotes. When a generation upgrade project is needed to provide additional capacity, Remotes works closely with the First Nation community through the funding and approval process. The First Nation community has the final say in the technical design of the project based on the feasible options outline by Remotes, which is usually the most cost effective option. Since this type of project must be customer-initiated, the year of execution depends on the First Nation community meeting all the requirements before starting the project and on the availability of INAC funding. Remotes mitigates this risk through its strong community outreach program and involvement of the First Nation representatives early in the planning process. Due to federal funding constraints and competing priorities for INAC capital, the available INAC funding is insufficient to finance required station upgrades in the communities; however, this issue was partially resolved in 2013 following extensive engagements with INAC. The resulting capital funding allocations commencing in 2014 relieved connection constraints in some of the communities. While Remotes is confident in the ability of the communities to secure funding planned incremental capacity upgrade projects based on strong relationship with INAC, it notes that external factors outside of its control always present certain risks. For instance, INAC operates on a fixed annual capital budget that covers all capital needs within communities, not just electricity, meaning that funding availability can be affected by emergency funding requirements in the IPAs communities, for other capital requirements or by centrally determined Federal Government's funding priorities.

Customer-Initiated Projects

The year-to-year changes in scope, nature, and volume of customer-initiated projects all affect Remotes' pace and prioritization of work execution activities. Customer-initiated projects include metering, service cancellations, damage claims, small external demand requests, fixed price layouts, new customer connections, and service upgrades. The level of expenditures required for these activities fluctuates between years based on the volume of work requested by customers. However, these fluctuations do not affect the rate base, since this work is 100% recoverable from the requesting customers.

Transportation Challenges

Transportation is the third major contingency affecting Remotes' project execution. Many of the First Nation communities are not accessible by year-round roads. While personnel can be flown to and from the communities, large assets such as generators and GSUs must be transported by land. To do this, the environmental conditions must be favourable to allow for safe transportation of heavy equipment along winter roads. An entire year can pass without a winter road to a community becoming available, in which case the project is typically deferred. Remotes has the option of hiring a specialized transport plane to deliver the heavy equipment when there is no winter road available, but the cost is not usually justifiable. Remotes accepts the risk posed by winter roads to its project execution as a part of its unique operating conditions and modifies its capital plans when required.

Resource Availability

There is a lack of skilled trades contract resources living in the communities, and there are very few contractors who work in them. Remotes employs regular and casual staff, apprentices, and contract staff to complete capital and maintenance work. Work in the communities requires a number of different skilled trades including line maintainers, distribution technicians, environmental technicians, mechanics, electricians, and carpenters who specialize in distribution system upkeep, generator upkeep, and civil construction. Remotes also uses specialized resources for tasks such as vehicle servicing hydroelectric maintenance, and SCADA/PLC upgrades. Internal resource deployment is prioritized based on the urgency of the work required. Remotes' overarching priority is to keep its generators running to keep the lights on in the communities. Depending on the scope and nature of unplanned work that arises from time to time, planned investments may be deferred if resources are unavailable. For instance, if there is an unplanned engine failure, resources can be pulled from capital jobs to perform maintenance work to keep the power on. To mitigate this risk, Remotes focuses on planned maintenance and capital upgrade work to reduce the amount of unplanned work that can stretch resource availability. Examples of planned projects and programs include distribution system improvements, generator overhauls, and generator replacements.

Regional Electricity Infrastructure Requirements

Remotes is a participant in the Regional Planning Process for the North of Dryden region, which is part of the Northwest Ontario Planning Region and covers the Remote Community Connection Plan. The 2014 draft Remote Community Connection Plan is a business case which informed a July 29, 2016, Order-in-Council from the Provincial Government. The Order confirms the need for the project to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes. The provincial and federal governments have indicated that communities must be served by licenced distributors to qualify for grid connection. Five of the communities now served by IPAs have now requested service from Remotes. Remotes expects to take over service of two of these communities within the next five years. The potential construction of a transmission line to the communities currently served by Remotes is not expected to affect the investments in the communities over the five-year period comprising this DSP, as the transmission construction activities are anticipated in the medium- to longer-term. As the transmission connection plans mature and firm up, Remotes will review its investment plans for the appropriate timeframes and make any amendments that may be warranted based on discussions with other parties involved.

Other Contingencies

Other contingencies that may affect the size and mix of capital investments over the forecast period include inclement weather, joint-use requests, and investments into minor fixed assets. While inclement weather can delay projects, it generally does not lead to project deferral; rather inclement weather is an investment driver for repairs to the distribution system due to ice, wind, and storms. Joint-use pole requests are included as part of the Distribution System Improvements program and are contingent on external requests by third parties such as Bell or the local First Nation. Planned work requirements include pole replacements and reframing to accommodate telecommunication lines on the poles. Customers benefit from the efficiencies realized due to joint-use of assets. Forty per cent of the cost of joint-use projects are funded by external parties. Investments into minor fixed assets are budgeted based on the expected needs each year, but the actual investments are driven by specific needs that occur within the year.

2.2 Coordinated Planning with Third Parties (5.2.2)

2.2.1 Records of Engagement (5.2.2a)

Remotes regularly engages its customers and leaders of the First Nation communities it serves, federal government agencies such as INAC, provincial government bodies such as the OEB and the Ministry of Energy, the IESO, and other electricity distributors and transmitters.

2.2.1.1 Customer Engagement

2.2.1.1.1 Customer Advisory Board Meeting

On June 23, 2016, Remotes held its annual Customer Advisory Board meeting.

Purpose of the Engagement:

The annual Customer Advisory Board meeting facilitates feedback from the Customer Advisory Board on several topics such as updates to the Ontario Electricity Support Program, priority setting, and REG investments.

Engagement Initiation:

Remotes initiated the engagement.

Other Participants in the Engagement:

Other participants in the engagement are members of the Customer Advisory Board. The Customer Advisory Board includes commercial and residential customers in representing communities serviced by Remotes. Customers apply to be members of the Board and Remotes' management chooses representatives based on these applications. Customers must live or work in Remotes' service territory, be willing to attend meetings, and be willing to offer constructive advice about Remotes' services.

Final Deliverables

Members of the Customer Advisory Board voted to indicate their opinion regarding the prioritization of the company's key focus areas. The resulting relative priority allocation is shown in Table 2-5.

Table 2-5: Priorities Ranked by Customer Advisory Board

Work Program Component	Relative Customer Priority
Affordability	37.8%
Renewable energy	24.3%
Load growth	16.2%
Reliability	10.8%
Customer service	8.1%
Environmental protection	2.7%

Effect on the DSP

When setting its priorities for planning and ranking projects, Remotes took into consideration the priorities of its Customer Advisory Board outlined in Table 2-5. More information regarding the impact of this prioritization on the company's planning can be found in Section 4.2.

2.2.1.1.2 Customer Workshop

On November 23 and 24, 2016, Remotes jointly hosted a workshop with the Opiikapawin Services Limited Partnership, a partnership of the First Nation communities who are the majority owners of on the Watay project. Community representatives from nine of the communities Remotes serves were invited to attend the workshop. The community representatives each included a member the Band Council, a member of the Watay Board of Directors, and the community Remote Electrification Readiness Program worker (a community member who has been hired in the community to work on community readiness for connection to the grid). Representatives from INAC and OEB staff also attended this workshop.

Purpose of the Engagement:

The customer workshop provided an open discussion to plan for grid connection. The workshop also discussed Remotes' services, determined the preferences/priorities of the customers attending the workshop, and assisted OEB staff in carrying out their engagement with First Nation communities to determine First Nation Energy rates.

Engagement Initiation:

Together with the Tribal Councils, Remotes initiated the workshop.

Other Participants in the Engagement:

Other participants in the workshop included OEB staff, INAC, and the following First Nation communities:

- Bearskin Lake
- Big Trout Lake
- Kasabonika Lake
- Kingfisher Lake
- Sachigo Lake
- Wapekeka
- Weagamow Lake

Representatives from Sandy Lake and Deer Lake planned to attend, but weather restricted their travel.

Final Deliverables

The workshop provided recommendations in eight areas:

1. Backup generation: Remotes, INAC, and the First Nations will continue to work together to establish a backup generation plan for all the communities that are involved in the Watay project. Remotes will assess its own generation assets and will, on request from INAC and the local IPA community, assess the existing generation in the IPA communities. Further, each First Nation community representative will evaluate which individual buildings have backup generators installed (see Section 2.2.1.3.4 for more details). Any new construction of essential service infrastructure needs to include backup generation (school, clinic, water plant, sewage, etc.).

2. Environmental stewardship: Remotes and the First Nations will develop an environmental plan including annual reporting (see Section 2.3.4.2 on performance measures).

3. Affordability and rates: Participants expressed support for OEB staff's recommendations to make electricity more affordable for First Nation customers.

4. Customer Service: community representatives noted that most communications are with Band Councils and that Remotes should interact directly with community members. They expressed the desire for Remotes to hire a designated liaison in the First Nations who could engage directly with the community, improve accessibility to support programs (OESP and LEAP), and to improve disconnection communication with customers.

5. Priority setting: First Nation participants voted on a list of priorities for Remotes, indicating which aspects are most important to Remotes' customers.

Table 2-6: Priorities Ranked by First Nation Communities

Work Program Component	Relative Customer Priority
Environmental protection	21.5%
Community relations	14.9%
Renewable energy	14.9%
Customer service	14.0%
Affordability	14.0%
Reliability	11.6%
Safety	9.1%

6. Housing connections: Remotes should attend housing and public works conferences to improve understanding and communication between First Nations and Remotes on housing construction and permits.

7. Safety and emergency response: Remotes should provide information in electrical safety at regional conferences.

8. Community relations: Remotes should develop a Community Relations and Engagement Policy that includes Remotes and First Nation roles and responsibilities.

9. Access to conservation and renewable programs: Remotes should increase customer engagement when designing CDM and REG participation programs so that they are accessible, meaningful, and used.

The detailed summary of this workshop can be found in Appendix E: 2016 Customer Workshop.

Effect on the DSP

Based on this workshop and on discussions with Band Councils, Remotes has worked closely with First Nations and other parties on several renewable energy studies, which are discussed in further detail in Section 2.2.1.4.

When setting its priorities for planning and ranking projects, Remotes took into consideration the priorities of its customers outlined in Table 2-6. Environmental stewardship is consistently identified as paramount to the First Nation communities and is accounted in all stages of project planning, ranking, engineering, and design. More information about these priorities can be found in Section 4.2.1. Remotes has also identified several measures related to environmental stewardship that it tracks. These measures are listed in Section 2.3.4.

Remotes is registered to the rigorous ISO 14001 standard and aims for continuous improvements in all aspects of environmental management.

Specific investments have been planned over the forecast period with environmental protection in mind. Day and bulk fuel tank replacements are planned over the forecast period to ensure compliance with the latest codes and reduce the risk of a fuel leak. New diesel generator replacements and upgrades are much more efficient than older generators and offer better structural integrity, resulting in lower emissions and reduced risk of ground contamination through leaks. Distribution System Improvements include replacement of distribution transformers exhibiting signs of leaking oil or other defects. Storage building projects in the general plant category include construction of proper facilities for vehicle storage and maintenance that reduce the environmental risk of these activities. Remotes is also working with customers to deploy customer-owned renewable technologies.

Joint infrastructure planning between Remotes and the First Nation communities is a continuous process. Remotes attends housing and public works conferences to improve its understanding of the communities' concerns and priorities, and provide information regarding its own plans, risks, or constraints as may be relevant. These meetings also drive the budgetary process for new customer connections, service upgrades, and fixed price layouts. In respect to the costs of these services, Remotes endeavours to reduce its costs through the methods listed in Section 2.1.2, such as using standardized designs that are compliant with *Ontario Regulation 22/04*. Remotes has also created opportunities for the connection of customer-owned renewable generation, with 15 projects currently in service.

2.2.1.2 Engagement with INAC

Remotes operates in First Nation communities under funding agreements negotiated with INAC. Remotes and INAC representatives meet annually as a part of the ongoing planning program. Remotes also engages INAC regularly on the matter concerning the execution of specific projects and community outreach initiatives.

Purpose of Engagements:

The purpose of these engagements is to review the available generation capacity based on the historical and projected peak loads in the communities to forecast and plan necessary generation capital projects in the communities. Collaboration with INAC reduces costs and the overall risk related to power supply in the remote communities.

Engagement Initiation:

Remotes typically initiates the engagements.

Other Participants in the Engagement:

Other participants in the engagements typically include INAC's capital management staff and the assigned First Nation project management team.

Final Deliverables

Generation capital project meetings are held to initiate specific INAC-funded projects and to monitor project process. Once a project funding is initiated, Remotes participates and generally facilitates regular meetings. The meetings are held throughout the project to determine acceptable designs, timelines, and project progress. These meetings are held to meet the needs of the First Nation project management team and INAC capital management staff.

Effect on the DSP

Engagement with INAC is critical to the development and successful execution of generation upgrade projects listed in the system service category, given INAC's responsibility for capital project funding. Remotes and INAC have jointly identified the need to invest in Wapekeka, Fort Severn, Sandy Lake, Weagamow, and one of either Deer Lake or Kasabonika (to be re-evaluated over the forecast period) based on the available capacity and forecast load growth. These projects are entirely funded by the First Nation communities who, in turn, must apply for the funding from INAC. Remotes works closely with INAC to ensure the proper funding is in place for these projects to proceed.

INAC's role in the ultimate execution of the projects over the planned timelines is critical. In 2011, INAC experienced material funding constraints, rendering it unable to fund upgrades. As communities (and their load requirements) continued to grow, Remotes found itself in situations where it was unable to connect new electrical services. Remotes considered replacing engines with larger engines, but the cost to replace auxiliary systems was more expensive than funding a simple engine replacement, making these short-term solutions incompatible with the company's budgetary considerations and focus on efficiency. Following this experience, Remotes worked with INAC to modify the upgrade process so that smaller projects could be put in service quickly should a similar situation occur in the future.

2.2.1.3 Transmission Connection Engagement

Remotes participates in all aspects of the engagements related to the connection of several northern communities to the bulk transmission system. The key engagements are related to transmission connection planning, transmission connection funding, regulatory support for IPAs, and diesel generation backup.

2.2.1.3.1 Transmission Connection Planning

Purpose of the Engagement:

The purpose of this engagement is to plan a transmission line that, if built, would connect several First Nation communities currently served by Remotes, along with several IPAs, thus expanding the service territory of Remotes.

Engagement Initiation:

The IESO initiated the engagement.

Other Participants in the Engagement:

Other participants in the engagement were the IESO, First Nations representatives, and representatives from federal and provincial governments.

Final Deliverables

During 2013 and 2014, as part of this planning process, the IESO asked Remotes to provide information to support this planning process. Information provided included historical load in the communities, historical peak load information, and aggregated information historical diesel usage and costs. At the IESO's invitation, Remotes also has attended three broad stakeholder meetings where the IESO discussed future transmission plans in the northwest. Although no new stations are currently planned, a transmission connection date should eventually be provided.

Effect on the DSP

While the anticipated timeline of the transmission line construction falls outside the forecast period of the DSP, this project will affect Remotes' planning considerations over the medium-to-long term. In the interim period, Remotes continues to be required to offer reliable electricity service in the communities, and enable the load growth through capital upgrades funded by INAC. Remotes anticipates maintenance of the diesel generation assets until the day the transmission connection work is completed and a diesel backup study determines the optimal path forward. However, in recognition of this eventuality and as a means of managing its budget, Remotes reduced its funding requests for this interim period and has recommended customers to downsize their requests from INAC. An example of a project deferred in this manner, is the foregone Weagamow tank storage upgrade driven by the anticipated connection.

The revised upgrade process now allows for station modifications to allow customers to connect to the system. Remotes is also exploring innovative approaches to increase capacity such as the tie-line between Wapekeka and Big Trout Lake and the connection of customer-owned renewable energy in Fort Severn.

2.2.1.3.2 Transmission Connection Funding

Purpose of the Engagement:

The purpose of this engagement is to develop a funding agreement for the transmission connection project.

Engagement Initiation:

Watay Power initiated the engagement.

Other Participants in the Engagement:

Other participants in the engagement were Watay Power and representatives from federal and provincial governments.

Final Deliverables

Watay Power is the transmission company that was identified as the future owner-operator of the transmission line to be constructed. Watay Power is owned by 22 First Nations in the north in partnership with Fortis Ontario. The provincial government designated this project in July 2016. The letter from the Minister of Energy is attached as Appendix C: Order-in-Council from the Minister of Energy.

The Order-in-Council identified 16 communities to be connected to the bulk electricity grid at an undetermined date. Nine of these communities are presently served by Remotes, namely:

- Sandy Lake
- Deer Lake
- Kingfisher Lake
- Kasabonika
- Wapekeka
- Kitchenuhmaykoosib Inninuwug (Big Trout Lake)
- Bearskin Lake
- Sachigo Lake
- North Caribou Lake (Weagamow)

In addition, two communities identified in the Order-in-Council are expected to join Remotes' service area over the historical period, namely:

- Wunnumin
- Pikangikum

Effect on the DSP

This consultation has allowed Remotes to also explore innovative approaches to increase capacity such as the tie line between Wapekeka and Big Trout Lake. The new distribution line will be necessary once the transmission line reaches the communities; therefore, the incremental cost of building the line earlier than required is much less than the cost avoidance of a larger station upgrade in the communities.

2.2.1.3.3 Regulatory Support for IPAs

Purpose of the Engagement:

The purpose of these engagements is to educate communities served by Remotes and other First Nations operating IPAs on the provincial regulations related to electricity generation, transmission, and distribution.

Engagement Initiation:

The IESO and Watay Power initiated the engagements.

Other Participants in the Engagement:

Other participants in the engagement were the ESA, Watay Power, INAC, Ministry of Energy staff, and First Nation representatives.

Final Deliverables

As part of this effort, Remotes met with Chief, Council, and IPA representatives from North Spirit Lake, Wunnumin Lake, Muskrat Dam, Wawakapewin, Pikangikum, Poplar Hill, and Keewaywin. Information shared included ESA requirements, Ontario regulations, OEB programs, and rate setting. To ensure that distribution and generation assets meet provincial standards in the IPA communities, Remotes staff agreed to work with the ESA to inspect the assets in the communities and to identify defects that must be fixed ahead of grid connection. Inspections to date have taken place in Pikangikum, North Spirit Lake, and Wunnumin Lake. Reports are provided to the Tribal Councils and the local First Nations.

Effect on the DSP

Activities related to these engagements fall under the non-system O&M category and are not the focus of the DSP. The implementation of these activities will facilitate the successful connection of IPAs to the bulk electricity grid as part of the transmission connection project expected to take place in the medium-to-long term (outside of the planning period of the DSP).

Remotes has performed a considerable amount of work to help the northern IPAs prepare for anticipated grid connection. Based on the proposed transmission line route, the IPAs would be connected before any the communities served by Remotes are connected. The proposed line crosses the traditional lands of these communities, making their participation (and ultimate connection) a critical factor in the project's viability.

2.2.1.3.4 Diesel Backup Study

Purpose of the Engagement:

This is an ongoing engagement to assess the feasibility of using diesel generators as a backup power supply to reduce the outage times for remote communities to be served by a new radial transmission line.

Engagement Initiation:

The IESO initiated the engagement.

Other Participants in the Engagement:

Other participants in the engagement are the IESO, INAC, Watay Power, Tribal Councils, and Ministry of Energy staff.

Final Deliverables

The diesel backup study is exploring the development of technology options, regulatory considerations, current and future financial responsibilities, and environmental considerations. A draft study has been prepared for review by all parties involved. Additional community engagement is required before the report is finalized.

Effect on the DSP

The likeliest timeline of the transmission line construction falls outside of the forecast period of the DSP. This engagement has not had any commensurate effect on the DSP, but will affect Remotes over the medium-to-long term. The results of the study will determine Remotes' role in the implementation and operation.

2.2.1.4 Renewable Energy Studies

Purpose of the Engagement:

The Ministry of Energy tasked the IESO with identifying options for renewable energy in the three First Nation communities served by Remotes that the IESO has determined as not economic to connect to the grid (Whitesand, Fort Severn, and Gull Bay).

Engagement Initiation:

The Ministry of Energy initiated the engagement, which is being led by the IESO.

Other Participants in the Engagement:

Other participants in the engagement are the Ministry of Energy, INAC, and community representatives.

Final Deliverables

Remotes met with the IESO, the Ontario Ministry of Energy, and INAC to discuss its Renewable Energy Innovation Diesel Emission Reduction ("**REINDEER**") program and opportunities to expand renewable energy and renewable microgrid projects across the off-grid communities. To date, Remotes has completed a Connection Impact Assessment for a biomass project in Whitesand and has assisted the First Nation and the IESO with technical design aspects of the proposed project. Engagements are also underway for a solar/battery project in Gull Bay and a solar project being constructed in Fort Severn.

Effect on the DSP

For all three renewable projects under development, Remotes has a distinct role. First and foremost, Remotes must ensure safe and reliable power to its customers. As such, Remotes is taking an active role in design and technical review of project plans, with integration into existing systems as the core focus given all projects noted are in the initial development stage.

If developed as planned, the biomass generation project in Whitesand is expected to produce electrical output that would displace electrical load within the community and that settlement would be based on the avoided cost of diesel fuel in that community. No firm project timeline has yet been established for this project, although construction is planned to begin in 2025.

A solar generation project, supported by federal and provincial grants, is currently being developed by Fort Severn First Nation and private sector developers. Remotes' role in this project is to ensure the ongoing reliability and stability of the existing microgrid and to ensure that the project can be integrated into the existing generation system. The project is staged, with 40 kW of net-metered solar installed to date. When fully installed, the project will qualify for Remotes' REINDEER program and, consistent with that program, Remotes will pay for the electricity produced based on the avoided cost of diesel fuel.

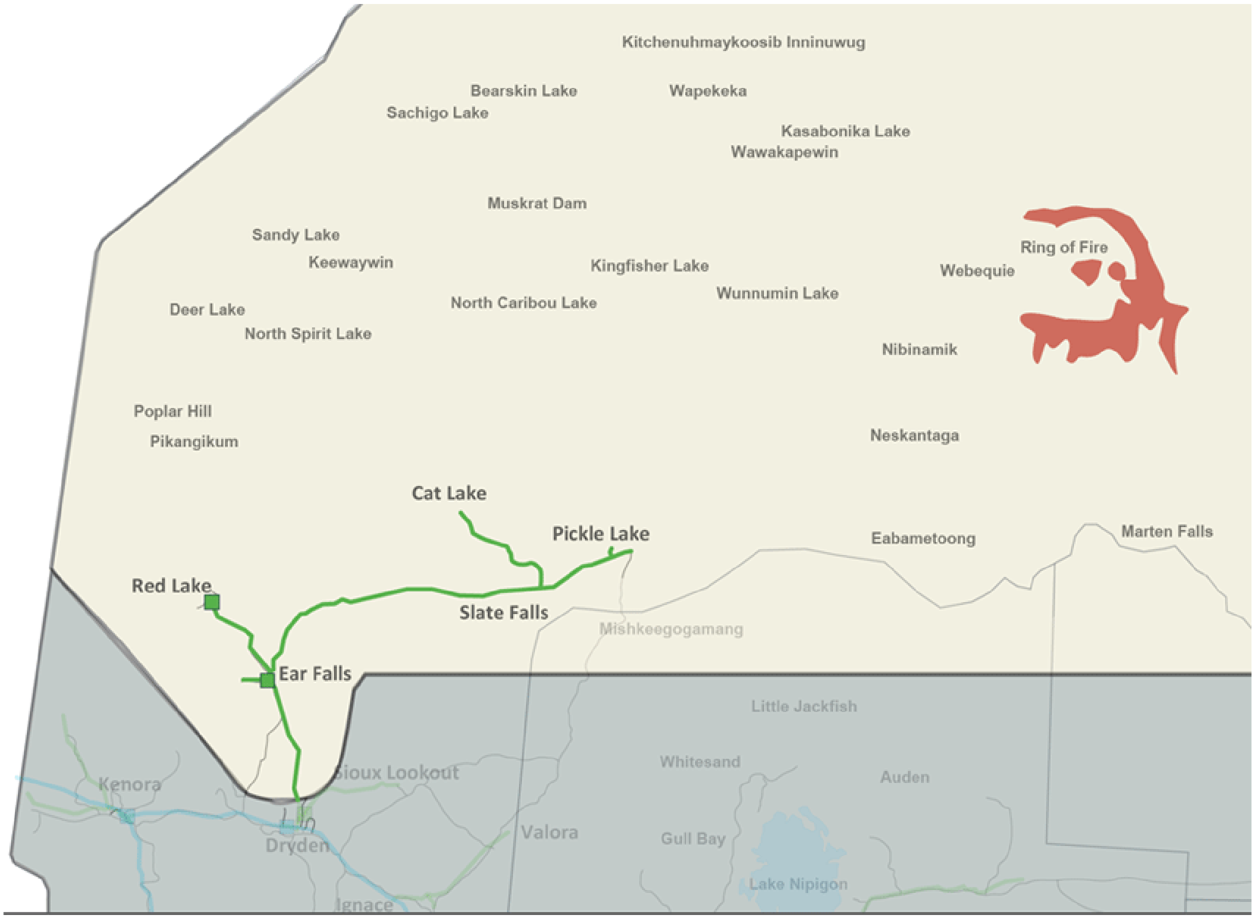
A high penetration solar/battery microgrid project, supported by provincial grants, is also planned for Gull Bay. The project is currently in the very early stages. It is anticipated that the project will also qualify for Remotes' REINDEER program and that settlement will also be based on the avoided cost of diesel fuel in that community.

In terms of generator upgrades and replacements, the three planned sites are not expecting upgrades over the forecast period. The upgrades will, however, affect future capacity.

2.2.2 Regional Planning Process (5.2.2b)

Remotes is part of the "North of Dryden" group for the Regional Planning Process. The North of Dryden area extends northward from Dryden to the towns of Ear Falls, Red Lake, Pickle Lake, and surrounding areas depicted in Figure 2-1. Electricity to the sub-region is currently supplied by the 115 kV Hydro One Networks Inc. transmission system. An Integrated Regional Resource Plan ("**IRRP**") was developed 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. Municipalities and First Nation communities were engaged in the development of the IRRP.

Figure 2-1: North of Dryden Area



The IRRP was published by the IESO on January 27, 2015. Drivers for increased electricity demand in the areas surrounding Red Lake, Pickle Lake, and the Ring of Fire include connecting 21 remote First Nation communities and growth in the mining sector. The IRRP recommended that a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake should be constructed along with 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. The IRRP is included as Appendix B: North of Dryden IRRP.

The OPA (now the IESO) and the representatives of the remote First Nation communities and tribal councils in the area drafted the 2012 Technical Report for the Connection of Remote First Nation Communities in Northwest Ontario. Since the release of the plan in 2012, engagement of the communities has continued and an updated draft Remote Community Connection Plan was posted in August 2014. The updated analysis identifies that there is an economic case to connect up to 21 remote communities at this time, including the Marten Falls First Nation. The remaining communities are not economic to connect at present, largely due to their relatively small size and distance from existing transmission infrastructure.

The 2014 draft Remote Community Connection Plan is a business case which informed a July 29, 2016, Order-in-Council from the provincial government. This order confirms the need for the project to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes and two are expected to be served by Remotes in the future. While this will not affect investments in the communities over the five-year period of this DSP, it is expected that the construction activities of this new transmission line will affect Remotes planning considerations over the medium-to-long term. The order from the Minister of Energy is included as Appendix C: Order-in-Council from the Minister of Energy.

2.2.3 IESO Comment Letter (5.2.2c)

A request for a letter of comment was sent to the IESO on March 3, 2017. The OEB expects the letter to include the following:

- the applications it has received from renewable generators through the Feed-in Tariff ("**FIT**") program for connection in the distributor's service area;
- whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments;
- and whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan.

In regards to those points, Remotes noted that:

- Remotes' service area is not eligible for the FIT program and, therefore, there are no FIT applications for connection in Remotes' service area;
- Remotes routinely consults with the IESO on various matters as appropriate;
- Each of the communities served by Remotes is electrically isolated and not connected to the bulk transmission system. Therefore, co-ordination with other distributors and/or transmitters on implementing REG investments is not necessary.
- The Remote Community Connection Plan is still under development for Remotes' region.

The letter sent to the IESO is included as Appendix F: Request for IESO Comment Letter and their response is included as Appendix G: IESO Comment Letter.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

This section identifies and defines the methods and measures used to monitor distribution system planning process performance, sets targets, reports on historical performance, and explains how this information has been incorporated into the DSP. These address the three performance outcomes listed in the Filing Requirements; customer-oriented performance, cost efficiency and effectiveness, and asset/system operations performance, environmental stewardship, and safety. Table 2-7 summarizes the performance measure to be tracked by Remotes and the desired outcome for each.

Table 2-7: Summary of Performance Measures Tracked by Remotes

Performance Outcomes	Performance Categories	Measures	Desired Outcome
Customer-oriented Performance	Customer Satisfaction	Customer satisfaction survey results	≥90%
	Consumer Bill Impacts	Percentage annual rate increase	3% during a Cost of Service year, 2% otherwise
	System Reliability	SAIDI including Loss of Supply	≤11.24
		SAIFI including Loss of Supply	≤12.97
Cost Efficiency and Effectiveness	DSP Implementation Progress	Gross CAPEX + system O&M – planned vs. actual	≥90%
Asset/System Operations Performance	Distribution Losses	Percentage line loss	≤3.6%
	Diesel Generation Efficiency	Energy generated from diesel per liter of fuel	≥3.42 kWh/L
	Percentage of Energy Generated from Renewables	Energy generated per liter of fuel issued (includes non-diesel)	≥2.41%
	Generation Availability	Percentage of generation availability	≥99.94%
Environmental Stewardship	Environmental Protection	Litres lost to the environment	≤100
		Number of spills	≤6
		Number of category A spills	0
	Greenhouse Gas Emission	Emission of carbon dioxide equivalents	Monitor emissions and calculate net emission intensity
		Net emission intensity	≤0.000731 tonnes per kWh
Safety	Lost-time Injuries	Number of lost-time injuries	0
	Total Recordable Injuries	Number of recordable injuries	≤2

2.3.1 Customer-oriented Performance

Customer focus is a key outcome of the RRFE. Therefore, Remotes has identified several measures for customer-oriented performance in the categories of customer satisfaction, consumer bill impacts, and system reliability.

2.3.1.1 Customer Satisfaction

The satisfaction of its customers is very important to Remotes. The motivation for tracking this metric is based on consumer, regulatory, and corporate drivers.

2.3.1.1.1 Definition (5.2.3a)

Customer survey results are used to gain insights into Remotes' performance relative to customers' needs and expectations. Customer surveys have been conducted approximately every two years since 2003. In 2015, Viewpoints Research conducted its most recent telephone survey of 205 residential, business, and government-supported organization customers served by Remotes.

Customer satisfaction is measured as the percentage of customers who responded "very satisfied" or "satisfied" with the electrical service they receive from Remotes, as reported in the customer satisfaction survey. Remotes' target for overall satisfaction is to be greater than or equal to 90 per cent.

2.3.1.1.2 Historical Performance (5.2.3b)

Figure 2-2 depicts the customer satisfaction survey results for each year of the survey.

Figure 2-2: Customer Satisfaction with Electrical Service

Overall satisfaction with the electrical service received from Remotes in 2015 is 91%, which is above the target. This is similar to levels recorded in 2009 and 2011 but is down from the 97% reported in the previous survey.

2.3.1.1.3 Effects on the DSP (5.2.3c)

Customers were asked to indicate the primary reason(s) for satisfaction with Remotes. Table 2-8 summarizes the reasons for satisfaction cited by customers.

Table 2-8: Reasons for Customer Satisfaction

Reasons for satisfaction	2015	2013	2011	2009	2007	2005	2003
Electricity there when needed	65%	51%	49%	40%	42%	43%	43%
Good/improved service	20%	15%	26%	18%	20%	19%	19%
Reliability has improved	12%	17%	25%	20%	12%	10%	10%
Fair rates	4%	6%	10%	5%	5%	6%	6%
Customer service	10%	10%	11%	13%	3%	4%	4%
Company doing the best they can	4%	2%	6%	5%	3%	4%	4%
Environmental practices	0%	1%	2%	2%	<1%	1%	1%
Rates/problems not their fault	1%	NA	NA	NA	NA	NA	NA
No reason/other/unsure	12%	19%	10%	27%	26%	26%	26%

Percentages do not total 100% because customers were permitted more than one response.

Having electricity available when they want it continues to be the main driver of customer satisfaction, as was identified by 65% of the surveyed utilities. This is 14% more than the previous survey in 2013, and 25% more than in 2009.

Twenty per cent of customers attributed their satisfaction to good or improved service, and 12% listed improved reliability. Satisfaction with customer service has held steady during this time, with ten per cent of customers indicating this as a key reason for their satisfaction.

The results indicate a need to continue to invest in system reliability as the main driver for customer satisfaction. Remotes has identified several investments over the forecast period planned to improve reliability. Distribution System Improvements replace defective poles, restring conductors, and re-align poles based on asset condition, to improve the system's reliability during storms. Distribution System Improvements also include the installation of new Viper switches to isolate upstream customers from downstream power outages. On the generation side, Remotes performs generator replacements and overhauls in accordance with manufacturer's recommendations to maintain the reliability of its supply. While not primarily driven by reliability improvements, generator upgrade projects have the added benefit of improved power supply reliability.

2.3.1.2 Consumer Bill Impacts

Remotes understands that the cost of living in the north is high. Remotes dedicates significant efforts to keep monthly bills affordable and works with its customers to facilitate timely bill payments. Remotes helps its customers conserve electricity, arrange payment programs, and find programs and services to reduce the overall cost of electricity. The motivation for tracking this metric is based on consumer and legislative drivers.

2.3.1.2.1 Definition (5.2.3a)

Remotes tracks the percentage of annual rate increase for the total bill payable by a typical year-round residential customer who consumes 750 kWh/month. The bill impact for all customers, including residential, is limited to the average distribution increase in a Cost of Service year, historically about three per cent, and by inflation in other years, historically about two per cent, based on legislative requirements.

2.3.1.2.2 Historical Performance (5.2.3b)

The 2013 rate year was the last Cost of Service application for Remotes. and a typical year-round residential customer (750 kWh/month consumption) would have seen a 3.41% bill increase. Table 2-9 depicts the annual percentage bill increase for a year-round residential customer each year from 2013 to 2017, as well as the five-year average.

Table 2-9: Annual Bill Impacts for a Year-Round Residential Customer (2013-2017)

Year	**2013**	**2014**	**2015**	**2016**	**2017**	**5-year Average**
Percentage Annual Consumer Bill Increase	3.45%	1.7%	1.6%	2.1%	1.9%	2.15%

2.3.1.2.3 Effects on the DSP (5.2.3c)

The projects and programs planned in this DSP have been paced and prioritized with consumer bill impacts in mind. To lessen its rate impacts, Remotes has implemented and will continue to implement several cost-saving measures such as those listed in Section 2.1.2.

2.3.1.3 System Reliability

Remotes' goal is to ensure that the power is there when customers reach for the switch. The motivation for tracking this metric is based on consumer, regulatory, and corporate drivers.

2.3.1.3.1 Definition (5.2.3a)

The key metrics that Remotes tracks to measure reliability are the System Average Interruption Frequency Index ("**SAIFI**"), System Average Interruption Duration Index ("**SAIDI**"), and Customer Average Interruption Duration Index ("**CAIDI**"). SAIFI is the average frequency of sustained power interruptions and is calculated by dividing the total number of customer interruptions over a given year by the total number of customers served. SAIDI is the average outage duration and is calculated by dividing the total number of customer-hours of sustained interruptions over a given year by the number of customers served. An interruption is considered sustained if it lasts for at least one minute. CAIDI reflects the average time for electricity service to be restored following an outage and is calculated by dividing the total customer-hours of sustained interruptions over a given year by the total number of sustained interruptions for that year (also by dividing SAIDI by SAIFI).

Over the historical period, Remotes' targets for SAIDI were 12.4 hours including loss of supply and 5.13 hours excluding loss of supply. Its SAIFI targets were 15.6 interruptions including loss of supply and 3.79 interruptions excluding loss of supply.

Over the forecast period, Remotes' target for SAIDI is 11.24 hours including loss of supply and its target for SAIFI is 12.97 interruptions including loss of supply. Remotes does not maintain a target for SAIDI or SAIFI excluding loss of supply since, from the customers' perspective, the reason for a power outage is not as important as the power outage itself.

Remotes does not set a target for CAIDI since, being the ratio of SAIDI to SAIFI, it is a redundant metric and CAIDI can increase while SAIDI and SAIFI both improve. Moreover, CAIDI was recently removed from the OEB's *Reporting and Record Keeping Requirements*. However, historical information on CAIDI is included for reference, as mandated by the Filing Requirements.

2.3.1.3.2 Historical Performance (5.2.3b)

Figure 2-3 and Figure 2-4 show the SAIFI and SAIDI performance with and without loss of supply for the years 2013 to 2016.

Figure 2-3: SAIFI Including and Excluding Loss of Supply (2013-2016)

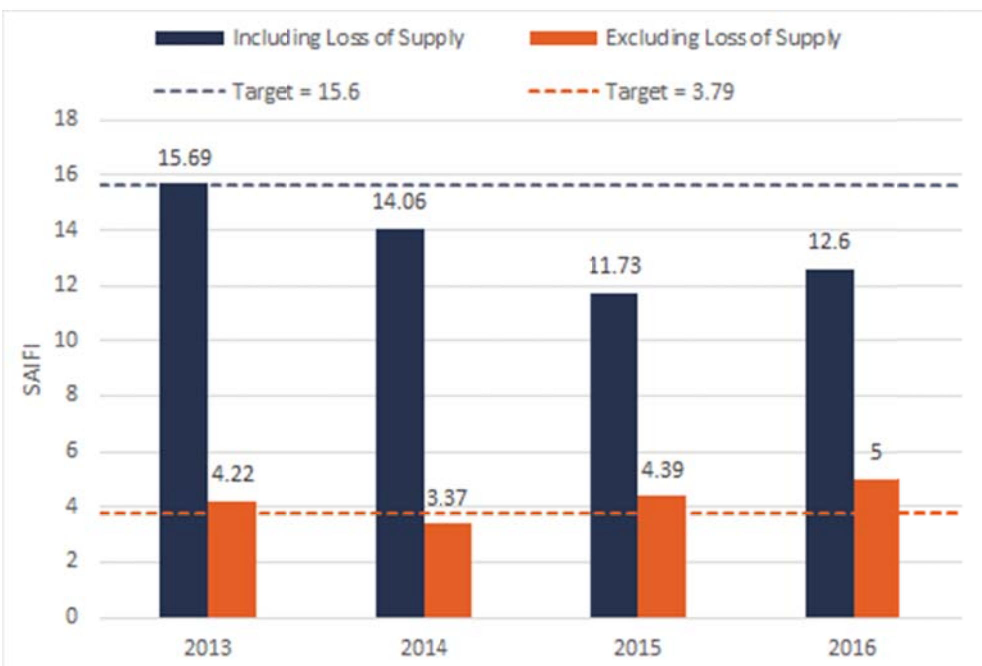
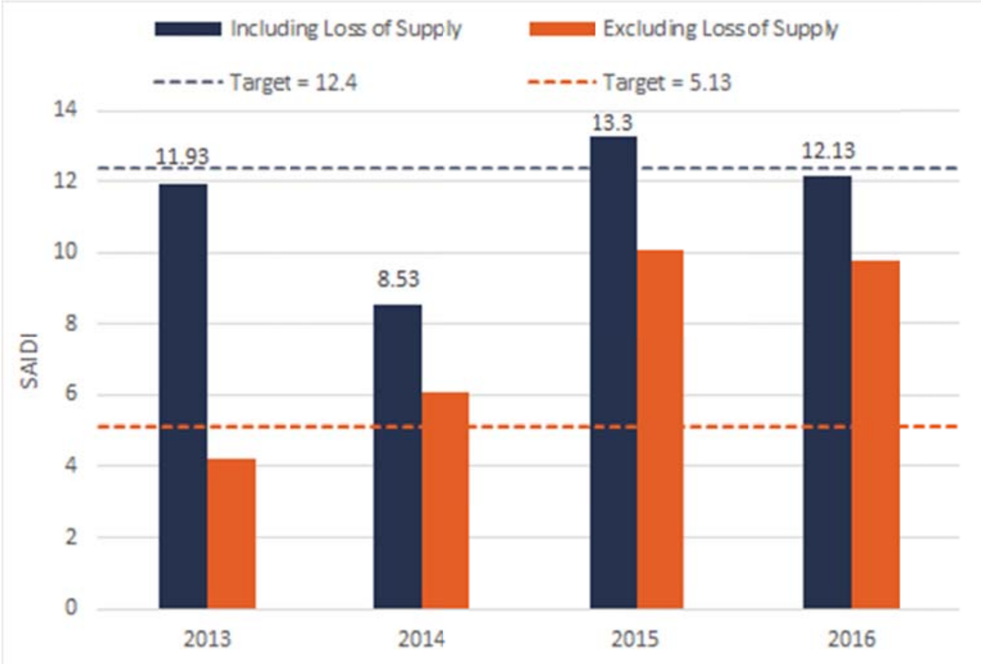


Figure 2-4: SAIDI Including and Excluding Loss of Supply (2013-2016)



When including loss of supply, both the SAIFI and SAIDI are below or very close to the target over the historical period. Excluding it, however, both metrics have exceeded the targets over the past several years, with SAIDI doing so by a significant amount. Based on the IEEE Standard 1366-2012 definition of a Major Event Day ("**MED**"), Remotes has not experienced any MEDs in any of the communities it serves.

Remotes has increased the number of planned distribution outages compared to 2012, which is the primary reason for the above-target performance. In addition, Hillsport had a major outage due to aging equipment where parts are no longer readily available. A new part was able to be fabricated locally to restore equipment to reliable service. This is a small community with just 32 customers, so it would be impractical to allocate a lot of capital to this community. Remotes pre-purchased two new generators so that if one fails it can be replaced by the other. Other material contributing factors to the SAIDI and SAIFI results include a commissioning-related outage at Weagamow, a bulk tank lockout at Deer Lake, an extended outage on the Collins line, and a long outage in Gull Bay.

Table 2-10 and Table 2-11 summarize Remotes' reliability performance over the historical period of 2013-2016, including CAIDI. The annual performance is highlighted for years when the target was not met.

Table 2-10: Customer Service Indicators Results with Loss of Supply

Performance Measure	Target	2013	2014	2015	2016
SAIDI	≤12.4	11.93	8.53	13.3	12.13
SAIFI	≤15.6	15.69	14.06	11.73	12.6
CAIDI		0.76	0.61	1.13	0.96

Table 2-11: Customer Service Indicators Results without Loss of Supply

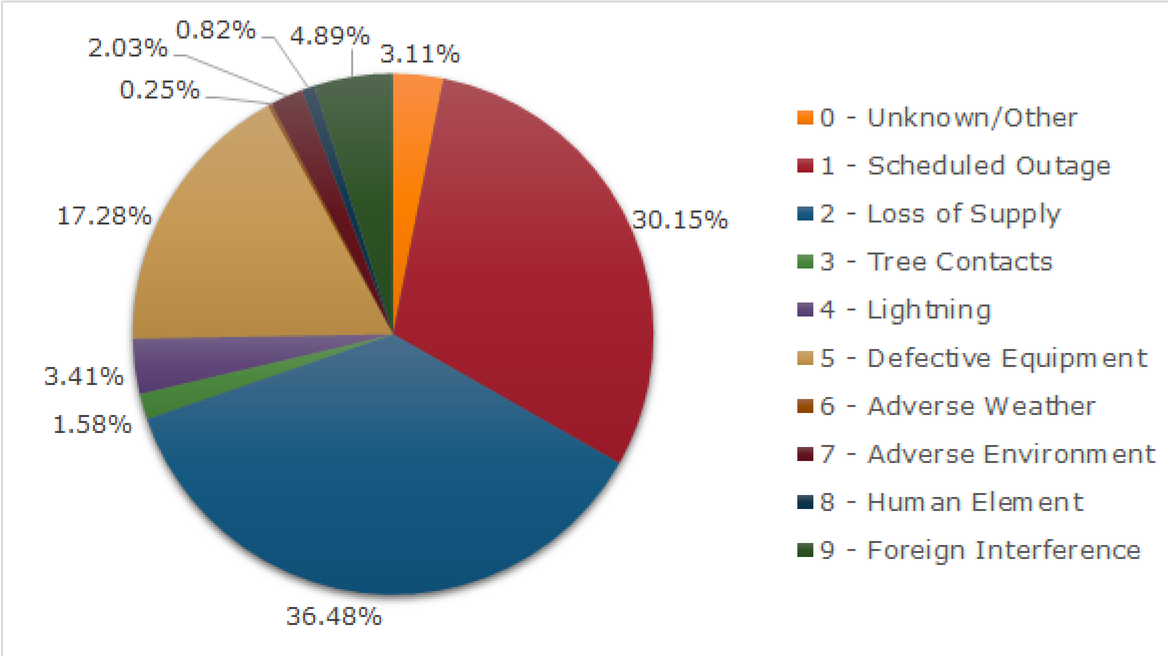
Performance Measure	Target	2013	2014	2015	2016
SAIDI	≤5.13	4.21	6.06	10.08	9.81
SAIFI	≤3.79	4.22	3.37	4.39	5.0
CAIDI		1.00	1.80	2.30	1.96

2.3.1.3.3 Effects on the DSP (5.2.3c)

Over the historical period, SAIDI has trended upward while SAIFI has trended downwards. Therefore, while the average duration of interruptions experienced by customers has increased, the average number of outages experienced has decreased. One way to reduce outage durations is through a fast response time. Remotes has a highly trained and skilled workforce including engineers, mechanics, line maintainers, electricians, and technicians stationed in Thunder Bay who are prepared to respond to an emergency 24 hours a day, seven days a week. In addition, there are trained operators in the communities who can respond to outages. However, if skilled trades are required to fix the cause of the outage, transportation can hinder power restoration efforts.

Remotes monitors and analyzes the root cause of power interruptions. Each power outage that occurs on Remotes' distribution system is recorded and an outage cause code is assigned. The number of customer interruption hours for each cause code provides a picture of the root cause of power interruptions. Figure 2-5 depicts the customer interruption duration by cause code for the years 2013 through 2016. The top three categories affecting Remotes' reliability are loss of supply (36.48%), scheduled outages (30.15%), and defective equipment (17.28%).

Figure 2-5: Customer Interruption-Hours by Cause Code (2013-2016)



Loss of supply outages have had the biggest impact on Remotes' customers over the historical period. These outages occur due to problems at the generating station such as the generator, fuel supply system, station auxiliary systems, PLC, circuit breakers, or transformers. Remotes has planned several investments over the forecast period to address loss of supply outages. Generator overhauls are planned to refurbish the engine based on manufacturers' guidelines to maintain the reliable operation of the generator. After two overhauls, it is no longer economical to overhaul the generator and its replacement is planned. Remotes has planned several generator replacements over the forecast period based on the maintenance history of the unit, the number of engine-hours, and the asset condition. SCADA and PLC upgrades at Remotes' generating stations will improve outage response time by enabling remote alarm handling and troubleshooting.

Non-capital investments to reduce loss of supply outages includes planned maintenance on generators as described in Section 3.3.1.2. Remotes is in the process of reviewing which maintenance activities will be beneficial to manage its GSUs.

Scheduled outages were a large part of the power interruptions in 2016. Remotes mitigates the impact of these outages through proactive planning and advanced notice with the affected communities. The planning approach of bundling of work in a community should help to reduce the number of outages and duration customers experience on an annual basis.

Defective equipment caused 22% of the power outages affecting customers in 2016. Remotes has planned various projects and programs in the DSP to address defective equipment outages. On the distribution system, investments will be made to replace aging and defective poles, restring conductors, and realign poles. Remotes is also planning to install new Viper switches on its distribution system to protect upstream customers from downstream faults and to improve the cold load pickup capability of the system.

2.3.2 Cost Efficiency and Effectiveness

Cost efficiency and effectiveness with respect to planning quality and DSP implementation is an important part of the Filing Requirements. Therefore, Remotes has identified a measure for cost efficiency and effectiveness in the categories of DSP implementation progress.

2.3.2.1 DSP Implementation Progress

DSP implementation progress measures the success of the execution of the capital programs outlined in the DSP. The motivation for tracking this metric is based on regulatory and corporate drivers.

2.3.2.1.1 Definition (5.2.3a)

The metric used is actual gross capital spending and O&M as a percentage of the business plan. The target going forward is based on the historical period average: 90% or more, and reflects the uncertain amounts and timing of INAC funding, as well as contingencies related to the transportation of materials to the north.

2.3.2.1.2 Historical Performance (5.2.3b)

Historical performance is displayed in Table 2-12. The percentage of spending relative to plan varies due to reprioritization of work priorities during the year. Remotes' top priority is to keep the lights on and respond to trouble calls on the systems. The next priority is customer-requested work including connections and capacity upgrades. Since these projects are externally-initiated, Remotes' resources may be redeployed from planned capital projects to accommodate customer needs.

Table 2-12: Actual Spending as Percentage of Business Plan

Program	Historical				
	2013	2014	2015	2016	Average
Distribution					
Distribution O&M	80.30%	94.85%	92.64%	87.39%	88.80%
Distribution Capital	91.89%	73.92%	82.87%	80.56%	82.31%
Total Distribution	83.28%	88.85%	89.96%	85.47%	86.89%
Generation					
Generation O&M	101.65%	104.82%	81.19%	81.79%	92.36%
Generation Capital	64.65%	68.32%	141.54%	114.10%	97.15%
Total Generation	88.48%	92.74%	98.24%	89.09%	92.14%
Other					
Common O&M	109.35%	77.40%	75.45%	57.95%	80.04%
Environment O&M	120.09%	115.54%	100.60%	107.50%	110.93%
Facilities Capital	47.59%	78.55%	15.06%	128.03%	67.31%
MFA Capital	214.47%	93.66%	131.21%	62.96%	125.57%
Total Other	92.41%	96.67%	61.20%	101.14%	87.85%
Total Projects	88.76%	92.30%	89.73%	89.57%	90.09%

2.3.2.1.3 Effects on the DSP (5.2.3c)

Remotes' DSP has been informed by the targets derived based on historical performance measurement. Remotes carefully plans project expenditures through its budgeting process. Distribution capital investments have been planned in such a manner that they can be executed by Remotes' crews, apprentices and casual staff. Generation capital investments have been planned through considerable coordination with INAC and the remote communities. Remotes' generation capital budgeting process allows for investments to shift between communities as their needs evolve over the forecast period.

2.3.3 Asset/System Operations Performance

Asset/system operations performance provides a good measurement of Remotes' asset management strategy effectiveness. Therefore, Remotes has identified several measures for asset/system operations performance in the categories of distribution losses, diesel generation efficiency, total generation efficiency, and generation availability.

2.3.3.1 Distribution Losses

Losses on the distribution system increase the amount of energy generation required to serve the downstream load. Distribution losses should be minimized wherever possible. The motivation for tracking this metric is based on corporate drivers.

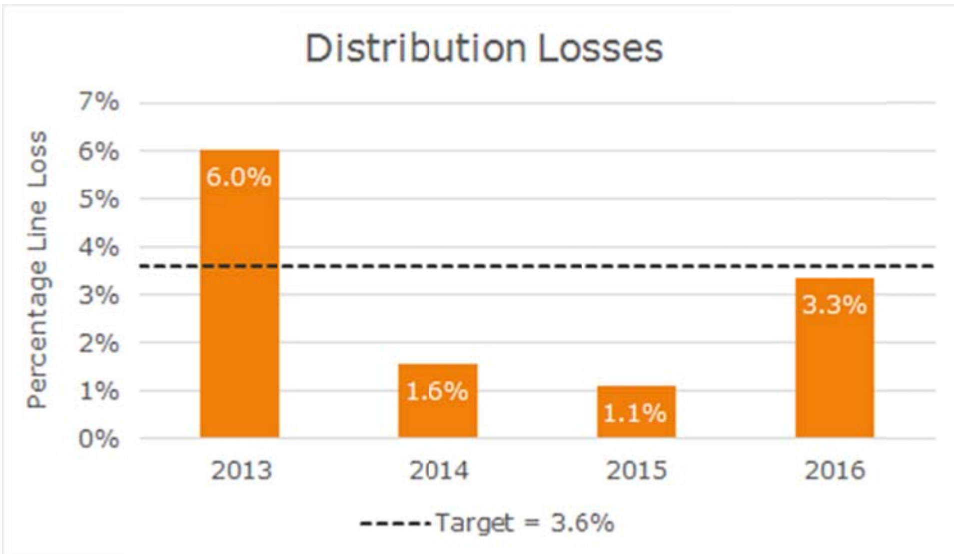
2.3.3.1.1 Definition (5.2.3a)

Remotes tracks its distribution losses as the difference between the energy generated and energy sold, measured as a percentage of the total energy generated (all in kWh). The target for this metric is 3.6% or less.

2.3.3.1.2 Historical Performance (5.2.3b)

The distribution losses over the last four years are presented in the figure below. Remotes exceeded its target in 2013, but has met the target since.

Figure 2-6: Distribution Losses 2013-2016



2.3.3.1.3 Effects on the DSP (5.2.3c)

Remotes has not planned any investments with distribution losses as the primary driver; however, Distribution System Improvements such as conductor restringing and distribution transformer replacements reduce losses on the distribution system.

2.3.3.2 Diesel Generation Efficiency

Remotes strives to improve the efficiency of its diesel generation fleet through its procurement process, maintenance programs, and capital investment strategies. The motivation for tracking this metric is based on corporate drivers.

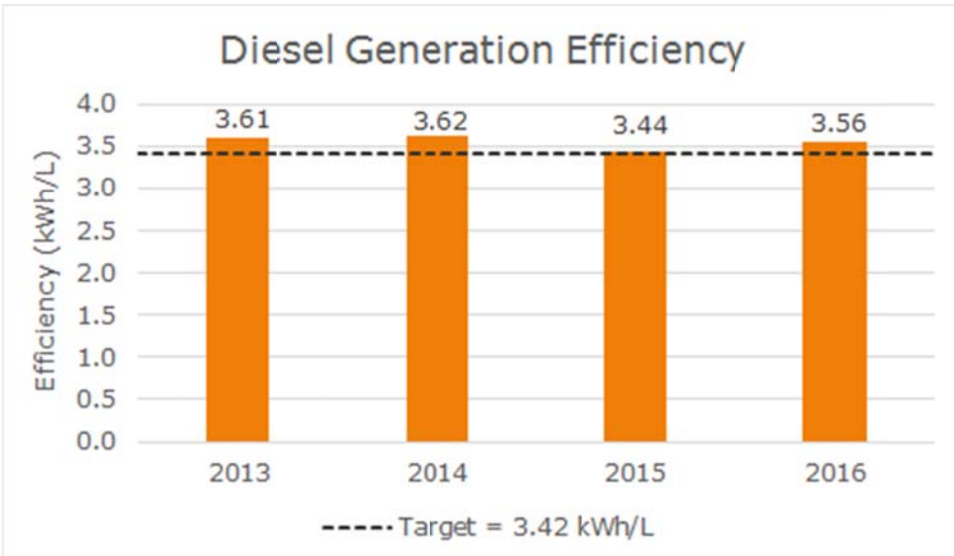
2.3.3.2.1 Definition (5.2.3a)

Remotes calculates its generation efficiency as the amount of energy generated (in kWh) per litre of fuel consumed. The annual target for this metric is an average of 3.42 kWh per litre or greater.

2.3.3.2.2 Historical Performance (5.2.3b)

Figure 2-7 depicts the efficiency of diesel generation for the years 2013 to 2016. The diesel generation efficiency is above target each year but has trended slightly downward since 2013. Diesel generation efficiency depends largely on the load profile in the community as optimized by the generator control scheme. Efficiency also depends on the number of out-of-service units.

Figure 2-7: Diesel Generation Efficiency 2013-2016



2.3.3.2.3 Effects on the DSP (5.2.3c)

To reverse the downward trend, Remotes will continue to invest capital into generation replacements and overhauls. Generator replacements planned over the forecast period replace older, less efficient generators with newer, more efficient ones. Generator overhauls planned over the forecast period improve the efficiency of the refurbished units. While not a significant driver for the investment, generator upgrades have the same efficiency benefit as the replacement projects. The generator upgrades are contingent on INAC funding.

2.3.3.3 Percentage of Energy Generated using Renewables

By investing in non-diesel generation assets, such as wind, solar, and hydroelectric, Remotes can reduce its reliance on diesel fuel, which is important to Remotes' customers.

2.3.3.3.1 Definition (5.2.3a)

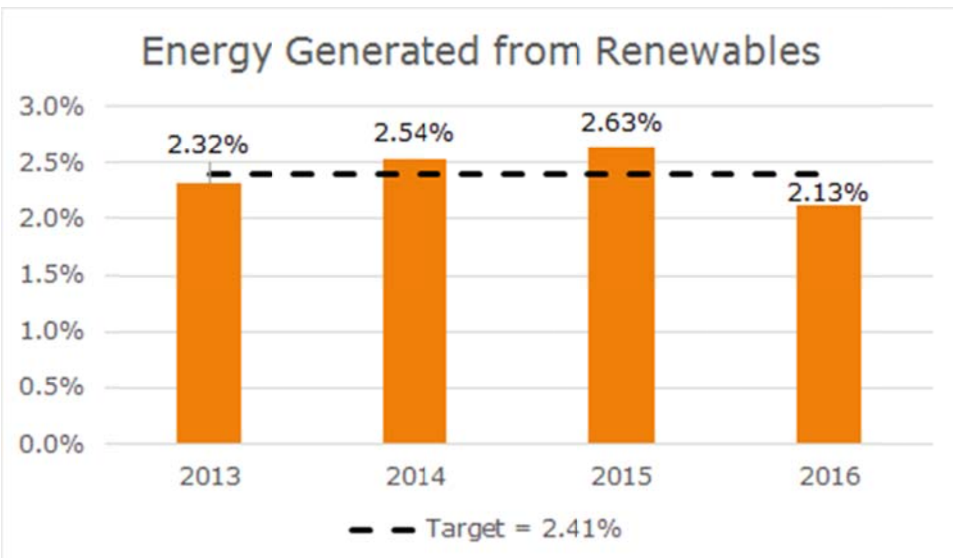
The percentage of energy generated using renewables is calculated by dividing the kWh generated from wind, solar, and hydroelectric sources (owned by Remotes) by the total kWh of energy generated by Remotes. The target over the forecast period is based on the historical period average: 2.41% or greater.

2.3.3.3.2 Historical Performance (5.2.3b)

Remotes currently owns three hydroelectric stations and four wind turbines. Remotes does not currently own any solar generation equipment, but projects in Fort Severn and Gull Bay are currently planned. Fifteen customer-owned solar installations are in service and more are planned.

Figure 2-8 depicts the percentage of energy generated from renewables for the years 2013 through 2016. The amount of energy generated each year fluctuates based on the demand in the community and, in the case of the wind turbines, due to intermittency of the source. The percentage of energy generated from renewables also depends on the condition of the generating units. Recent projects have refurbished, rebuilt, and overhauled the renewable generators to improve their condition. The drop in 2016 is largely due to less energy generated from the Deer Lake hydroelectric generators. In 2016, Deer Lake generated 31% of its total energy from renewable sources, which is close to the previous three-year average of 28%. However, total energy consumption in Deer Lake in 2016 was 21% less than the previous three-year average. Since 65% of Remotes' renewable generation capacity is installed in Deer Lake, the community's consumption affects the metric.

Figure 2-8: Percentage of Energy Generated from Renewable Sources (2013-2016)



2.3.3.3.3 Effects on the DSP (5.2.3c)

There are no capital investments into the existing renewable generator fleet planned over the forecast period, since refurbishments are to be made over the forecast period. Remotes will continue to maintain its renewable fleet to ensure its reliable operation. Several studies are underway to install biomass and solar projects in three remote communities, as described in Section 2.2.1.4.

2.3.3.4 Generator Availability

Generation availability is a good indicator of the success of Remotes' capital and maintenance programs and provides an indicator for power reliability. The motivation for tracking this metric is based on consumer and corporate drivers.

2.3.3.4.1 Definition (5.2.3a)

Generation availability is calculated annually using the total duration of unplanned outages over the year. The availability is then the number of hours of unplanned outages subtracted from the number of hours in the year, as a percentage of the total number of hours in the year. Remotes' target for this metric over the forecast period is based on the historical period average: 99.94% or greater.

2.3.3.4.2 Historical Performance (5.2.3b)

The average generation availability for each year of the historical period is shown Table 2-13. Remotes exceeded its target in each of these years

Table 2-13: Percentage of Generation Availability 2013-2016

Year	2013	2014	2015	2016
Generation Availability	99.86%	99.97%	99.97%	99.96%

The methodology looks at all outages under OEB Cause Code 2 that are one (1) minute or greater.

2.3.3.4.3 Effects on the DSP (5.2.3c)

Similar to system reliability, generation availability drives investment into generation assets. Capital investment into Remotes' generation fleet, through planned replacements and overhauls, addresses generator availability. Generation upgrade projects also improve generation availability, since an older generator is replaced with a newer one and the decommissioned generator can be salvaged for spare parts to enable faster emergency repair times. Remotes' rigorous asset management program includes preventive maintenance on generators, which will reduce generator downtime.

2.3.4 Environmental Stewardship

Environmental stewardship is the top priority for many of Remotes' customers. Therefore, Remotes tracks an additional category of measures related to greenhouse gas emissions and environmental protection.

2.3.4.1 Greenhouse Gas Emissions

Most of Remotes' electricity is generated using diesel fuel since it is currently the most reliable and cost-effective method. Remotes is cognisant of the greenhouse gas contributions of its fleet and, therefore, monitors its emissions. The motivation for tracking this metric is based on consumer and corporate drivers.

2.3.4.1.1 Definition (5.2.3a)

Remotes tracks greenhouse gas emissions from its electricity generation fleet. Generators within the 19 generating stations burn diesel fuel to produce electricity, directly emitting greenhouse gases to the atmosphere.

The metrics tracked by Remotes that relate to greenhouse gas emissions are:

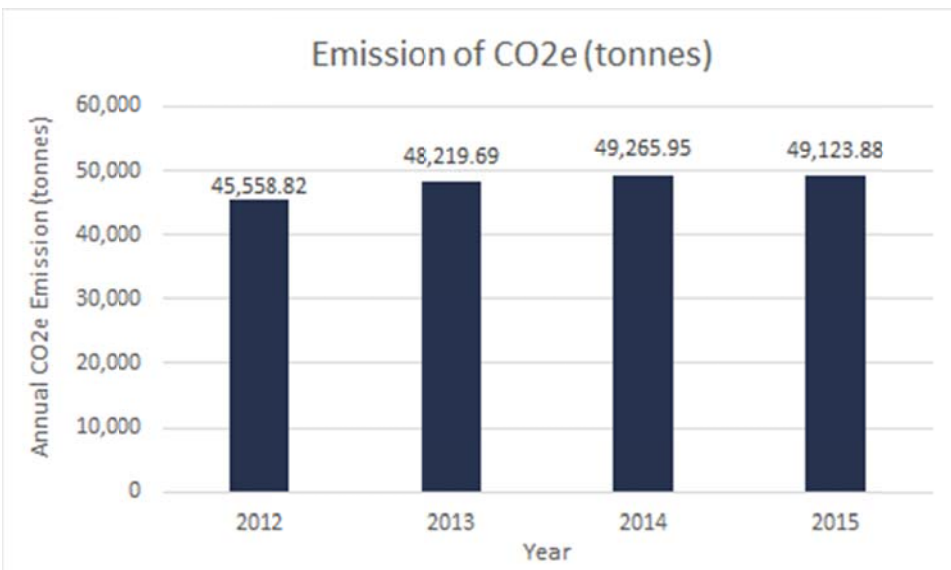
- Emission of carbon dioxide equivalents ("**CO_2e**") measured in tonnes.
- Net emission intensity (tonnes of CO_2e per kWh of total energy generated).

The target set for the emission intensity for 2015 is less than or equal to 0.000731 tonnes of CO_2e per kWh.

2.3.4.1.2 Historical Performance (5.2.3b)

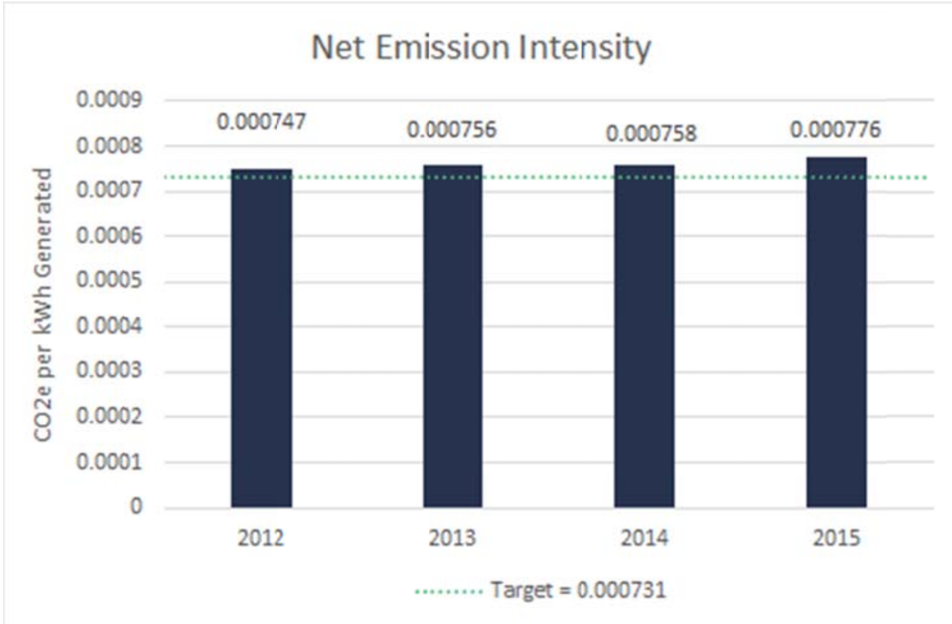
Figure 2-9 shows Remotes' CO_2e emissions from diesel electricity generation over the historical period of 2012 to 2015.

Figure 2-9: Greenhouse Gas Emissions from Generators 2012-2015



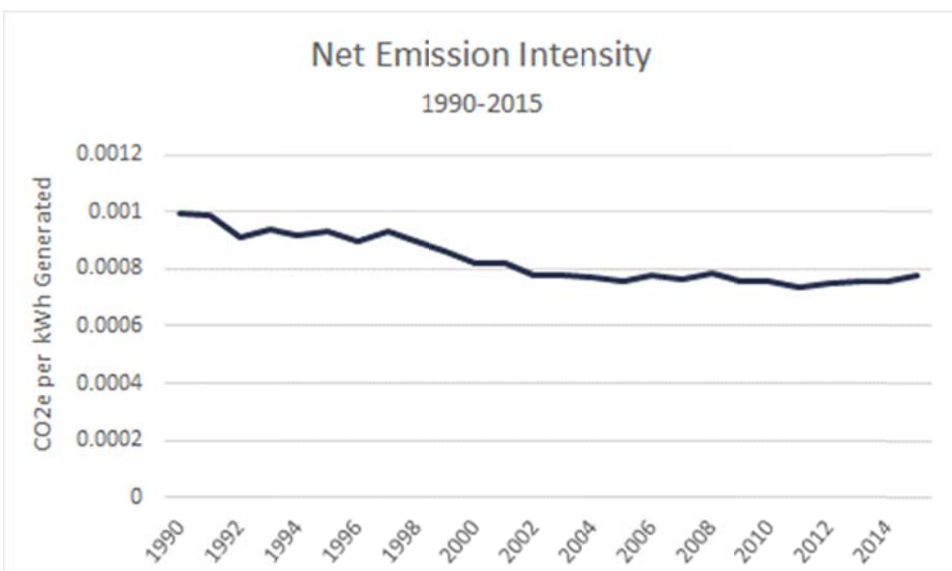
Remotes has increased its direct emissions from electricity generation for the past years. This is due to increases in the electricity demand. Therefore, Remotes' focus is to reduce its net emission intensity. The net emission intensity for the years is shown in Figure 2-10.

Figure 2-10: Net Emission Intensity from Generators 2012-2015



The net emission intensity has trended upward for the past few years and is above the target. This is due to less energy generated from renewable sources. As mentioned in Section 2.3.3.3, recent refurbishments to the renewable generators are expected to improve their reliability and reduce the net emissions intensity; however, the wind turbine generators will be run to failure since they are not economical to replace. This may affect the net emission intensity.

Figure 2-11: Tonnes of CO2e Emitted per kWh Generated 1990-2015



The long-term trend depicted in Figure 2-11 indicates that significant improvements have been made, but continued innovation is needed to further reduce the net emission intensity.

2.3.4.1.3 Effects on the DSP (5.2.3c)

Remotes has invested in renewable generation and offers the opportunity to purchase renewable electricity from its customers. Remotes is working with many local communities and their partners on high penetration renewable projects to help meet their electricity needs. Improvements in diesel generator technology will also improve the net emission intensity. As Remotes replaces older generators with newer ones through its replacement and upgrade programs and overhauls generators, it is expected that the net emission intensity will decrease.

2.3.4.2 Environmental Protection

Remotes works hard to reduce its overall environmental impact and takes environmental protection seriously. Metrics tracked under this category are high-priority to the First Nation communities served by Remotes. The motivation for tracking these metrics is based on legislative, consumer, and corporate drivers.

2.3.4.2.1 Definition (5.2.3a)

The metrics tracked in this category are:

- Litres of fuel lost to the environment
- Number of spills
- Number of Category A spills

The *Ontario Environmental Protection Act* defines "spill" as, when used with reference to a pollutant, means a discharge

1. into the natural environment;
2. from or out of a structure, vehicle, or other container; and
3. that is abnormal in quality or quantity considering all the circumstances of the discharge.

The measure for the number of spills refers only to spills caused by Hydro One Inc. personnel (including Remotes' personnel).

A "Category A" spill is defined as a spill which causes or may cause one or more of the following adverse effects:

1. Widespread injury or damage to plant or animal life.
2. Harm or material discomfort to any person.
3. An adverse effect on the health of any person.
4. The impairment of the safety of any person.

Remotes' annual targets are not more than 100 litres of fuel lost to the environment, not more than six spills, and zero Category A spills.

2.3.4.2.2 Historical Performance (5.2.3b)

Table 2-14 summarizes Remote's environmental protection performance over the historical period.

Table 2-14: Environmental Protection Measures – Historical Performance

	Target	2013	2014	2015	2016
Litres of fuel lost to the environment	≤100	0	10	20	0
Number of spills	≤6	2	4	8	0
Number of Category A spills	0	0	0	0	0

In 2015, there was an increase in the number of spills reported due to:

- Renewed commitment on self-reporting including small spills.
- Training and education of both staff and operators on proper reporting procedure.
- Increase in transportation work equipment ("**TWE**"), therefore more TWE spills.
- Increase in coolant/antifreeze spills related to equipment failures.

As of 2015, staff and contractors were trained to report all spills, no matter how small, including emissions or stains from a parked TWE and small spills within the diesel generating station, which Remotes staff previously just cleaned up.

2.3.4.2.3 Effects on the DSP (5.2.3c)

Several projects and programs planned over the forecast period reduce the risk of spills or fuel lost to the environment. Several projects will replace bulk and day fuel tanks to bring them up to compliance and reduce the risk of a spill. Generator replacement, overhaul, and upgrade projects reduce the risk of fuel being lost of a spill occurring from the generator itself. On the distribution side, Distribution System Improvements replace distribution transformers showing signs of oil leak or significant deterioration.

2.3.5 Safety

Safety is very important to Remotes. In addition to including safety in its Corporate Mission and Corporate Values, Remotes tracks safety metrics on its scorecard.

2.3.5.1 Employee Safety

Remotes continuously strives for an injury-free workplace and measures employee safety in terms of lost-time injuries and recordable injuries.

2.3.5.1.1 Definition (5.2.3a)

The Workplace Safety and Insurance Board defines a lost-time injury as "when a worker suffers a work-related injury/disease which results in being off work past the day of accident, loss of wages/earnings, or a permanent disability/impairment". Remotes strives for zero lost-time injuries.

The U.S. Department of Labor's Occupation Health and Safety Administration defines a recordable injury as one that results in "death, days away from work, restricted work or transfer to another job, medical treatment beyond first aid, or loss of consciousness" and may also include "a significant injury or illness diagnosed by a physician or other licensed health care professional" even if it does not meet the aforementioned criteria. Remotes strives for less than two recordable injuries per year.

2.3.5.1.2 Historical Performance (5.2.3b)

The number of lost-time injuries for the years 2013 through 2016 is shown in Table 2-15. In 2013, employees experienced two exertion injuries and one slip/trip/fall that required medical attention.

Table 2-15: Employee Safety over the Historical Period

	Target	2013	2014	2015	2016
Number of lost-time injuries	0	0	0	0	0
Number of recordable injuries	≤2	3	1	1	0

2.3.5.1.3 Effects on the DSP (5.2.3c)

Safety is considered when planning any job; from the simplest repair to the most complicated capital construction. At a minimum, no project or program compromises safety. From a capital planning perspective, the proactive replacement of generation and distribution assets improves safety by reducing the probability of an incident due to an unplanned failure.

3 Asset Management Process (5.3)

Remotes' asset management process is the systematic approach used to plan and optimize ongoing capital and O&M expenditures on the isolated electrical systems it owns (i.e. generation and distribution assets). The purpose of this section is to provide the OEB and other stakeholders with an understanding of Remotes' asset management process, as well as direct links between the process and the expenditure decisions that comprise Remotes' capital investment plan.

3.1 Asset Management Process Overview (5.3.1)

This section presents Remotes' asset management objectives and the components of Remotes' asset management process.

3.1.1 Asset Management Objectives (5.3.1a)

Remotes applies established asset management principals in managing its assets. The management of Remotes' assets involves optimizing and sustaining the assets over their lifecycles and factors in performance, cost, and risk. The management of the assets is carried out consistent with Remotes' strategic direction.

Remotes' vision is to be the leading utility and a trusted partner to remote communities in Ontario's north. Its mission is to supply safe, reliable, and affordable electricity to remote communities by focusing on continuous improvement, operational excellence, and outstanding customer service.

Remotes' strategic asset management objectives are divided into four categories of strategic business values: health and safety, stewardship, excellence, and innovation. The objectives are derived from the following corporate mission and vision statements. They are ranked as follows:

1. Health and Safety

- Ensure public and worker health and safety.

2. Stewardship

- Align development work with government policies, priorities, and directives.
- Ensure safe, reliable and efficient operation of the Remotes' system.
- Ensure long-term sustainability of existing assets and equipment; system reliability and security; and customer satisfaction and environmental integrity.
- Meet all applicable regulatory, legal and industry requirements.
- Enable and facilitate efficient connection of customers and maximize connection of renewable resources.
- Facilitate and enable the effective transformation and re-configuration of Remotes' system into a modern, intelligent, and customer-centric system.
- Ensure compliance in meeting potential new environmental air emission requirements.
- Manage existing assets consistent with Remotes' environmental management system and with a strong focus on energy efficiency.

- Keep informed and identify potential integration options into the grid, and assess if there is a strong business case.
- Maximize/optimize useful asset life for overall cost-benefit by balancing competing requirements for operating performance, costs, and risks.
- Keep informed of Smart Grid advancement for appropriate application at the Remotes' distribution system.
- Level and prioritize sustainment work scope and volumes for greater effectiveness and flexibility within applicable resource constraints (e.g., financial, staff).
- Develop the Remotes' system with a strong focus on energy efficiency, environmental awareness, and meeting potential new environmental air emission requirements.
- Maintain an appropriate balance and flexibility between sustainment and development work.
- Discuss and collaborate with affected First Nations and Métis communities on development.
- Discuss and collaborate with affected public and stakeholders on related Remotes development.
- If directed by the government; manage existing third party remote community energy systems.

3. Excellence

- Develop, retain, and have available a skilled, trained, productive, and flexible workforce for sustainment work, development work, and operating work.
- Focus on properly-planned and preventive work which emphasizes excellence and safety in achieving results, while eliminating 'firefighting' and corrective maintenance.
- Ensure the effective development of modern, reliable, cost- effective, safe, efficient and flexible systems which are customer-oriented and meets customers' needs.
- Develop and operate the Remotes' system and manage existing assets, using quality information, including databases, information systems and processes.

4. Innovation

- Leverage innovative and practical technologies, processes and standards in the development and operation of Remotes' system, and to improve asset and system performance, operations, and maintenance.
- Leverage effective and innovative ways and means to meet the needs of customers, including customer choice and the enablement of value services to the customers.
- Demonstrate leadership in Remotes' system technology advancement.

3.1.2 Components of the Asset Management Process (5.3.1b)

Figure 3-1 depicts Remotes' asset management process for diesel generators, including the role of the Asset Condition Assessment ("**ACA**"). Diesel generators are maintained as per manufacturer-published recommendations, including complete overhauls after specified hours. After two (2) overhauls, a diesel generator is typically replaced as the lifecycle has then been extended twice, parts can become obsolete and to improve fuel efficiency. Some units may be identified for earlier replacement subject to specific issues discovered during its lifecycle. Replacement may be advanced or lengthened accordingly. The engine replacement program also includes work related to auxiliaries and sometimes station transformers and breakers. Auxiliary work is evaluated on a case-by-case basis given the site, the existing equipment in service and the proposed replacement. In the past, strong community load growth has triggered frequent station upgrades which involve replacing diesel generators prior to them reaching their full life term.

Figure 3-1: Remotes' Asset Management Process for Diesel Generators

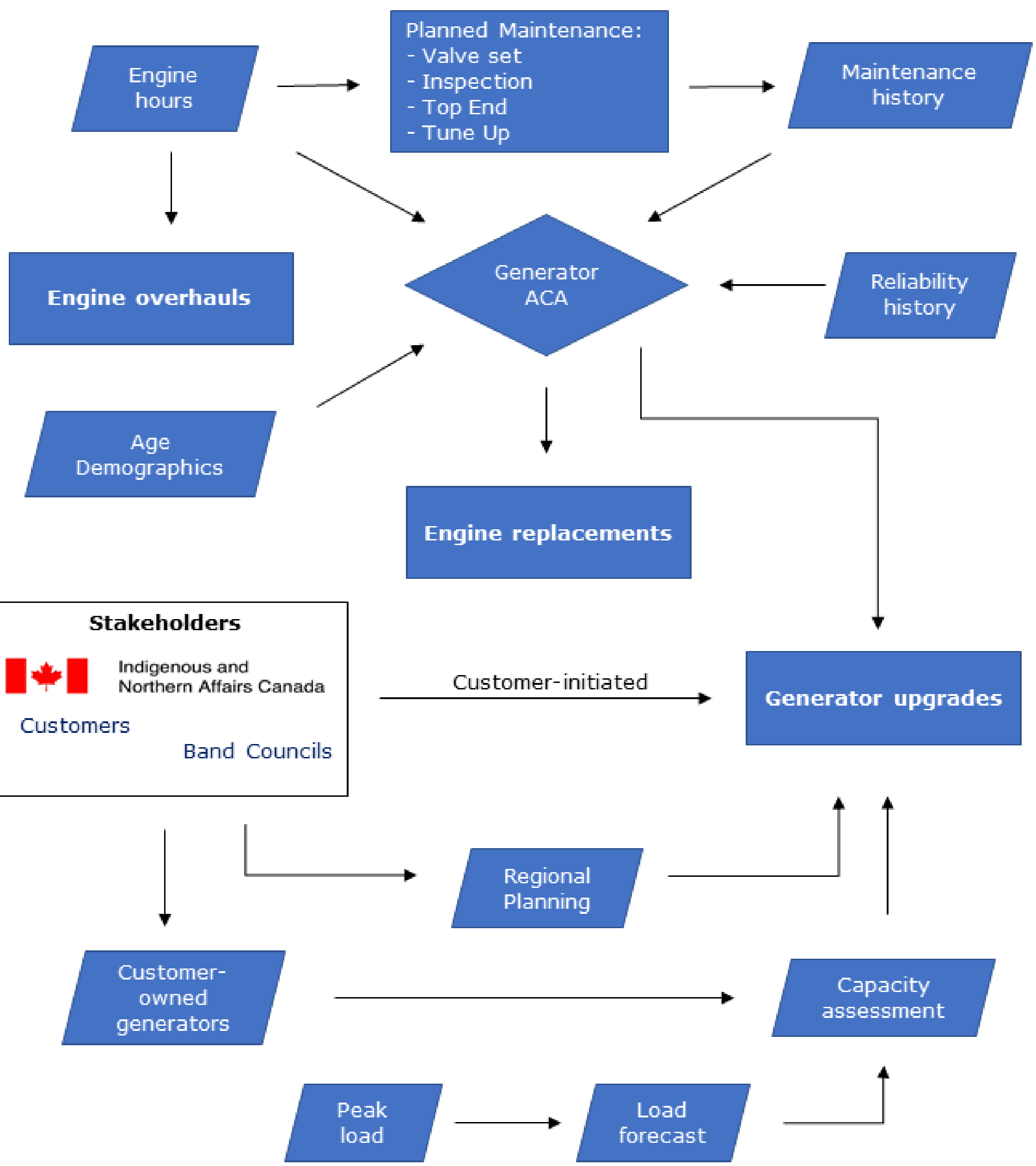


Figure 3-2 and Figure 3-3 depict Remotes' asset management process for its hydroelectric generators and wind turbines, respectively. Both types of generators undergo maintenance every six months. Capital work for hydroelectric generators, including replacement or refurbishment, is planned based on the ACA. The wind turbines owned by Remotes are run to failure.

Figure 3-2: Remotes' Asset Management Process for Hydroelectric Generators

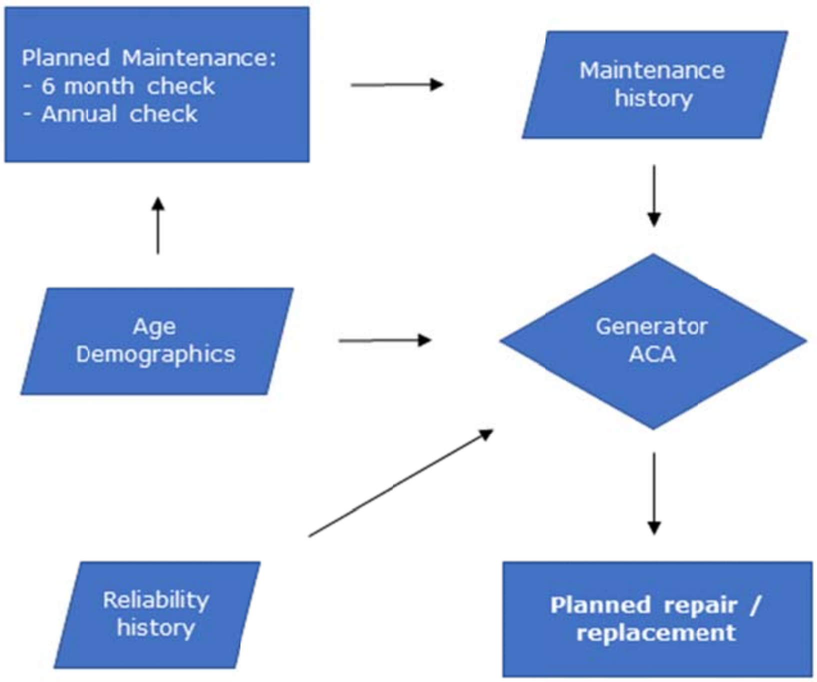
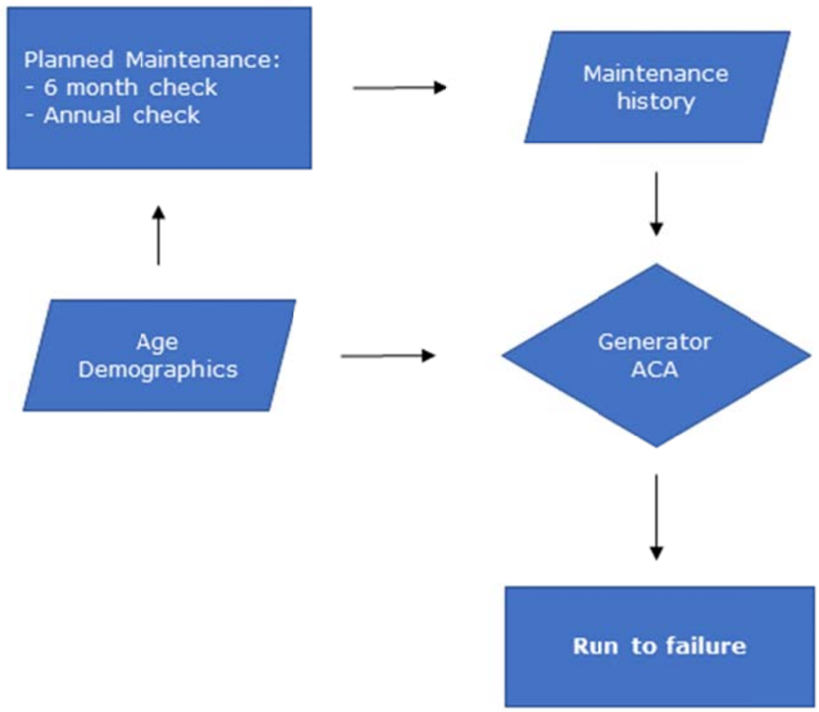
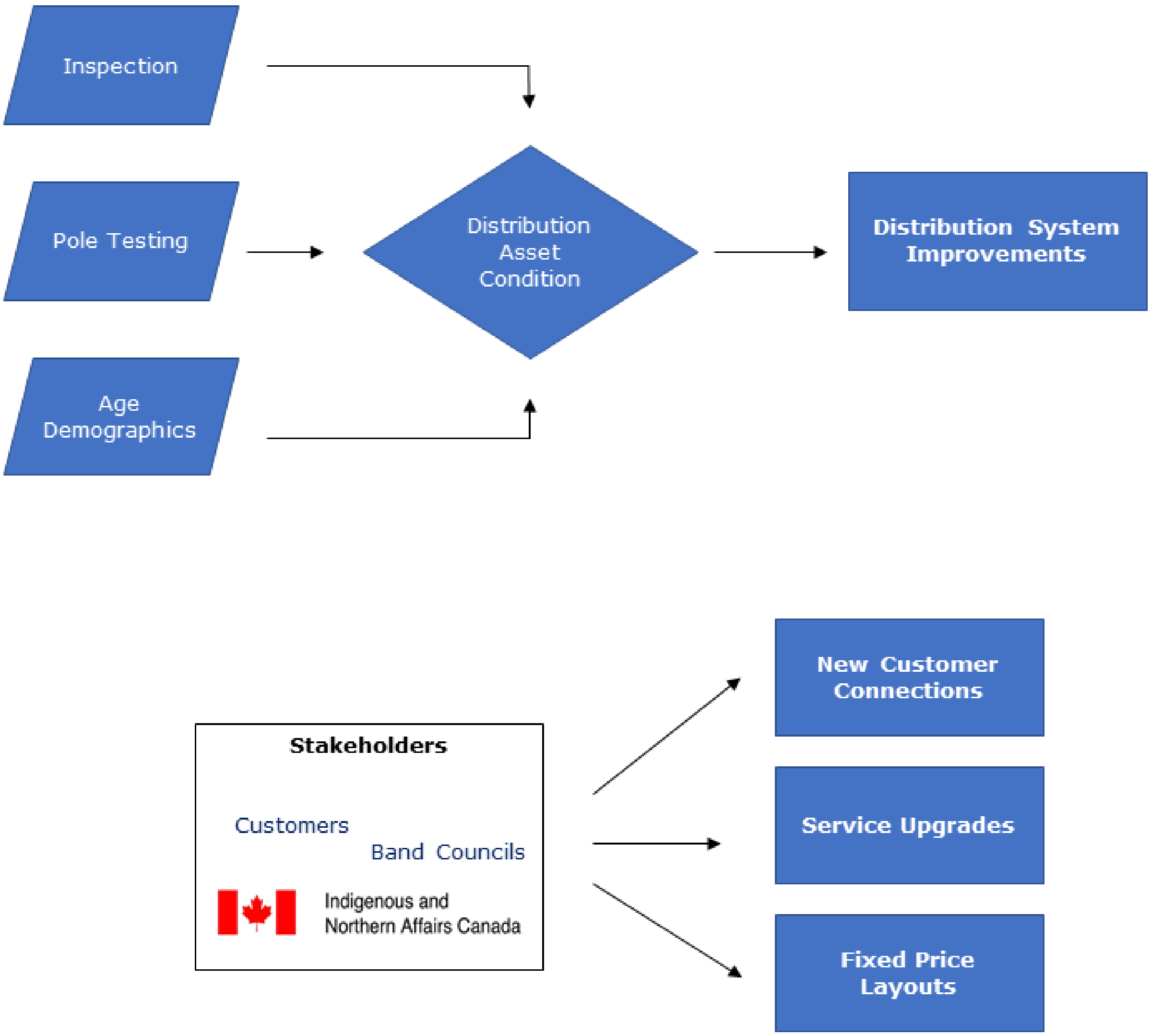


Figure 3-3: Remotes' Asset Management Process for Wind Turbines



On the distribution side, a community is selected for a betterment project each year based on asset condition, demographics and inspection results. This includes work such as pole replacements, conductor restringing, and pole re-alignment. New customer connections, service upgrades, and fixed price layouts are planned based on customer input. Figure 3-4 depicts Remotes' distribution asset management process.

Figure 3-4: Remotes' Distribution Asset Management Process



3.2 Overview of Assets Managed (5.3.2)

This section presents a description of Remotes' service area, a summary of the system configuration, demographic and condition information for major distribution and generation assets, and the system utilization relative to planning criteria.

3.2.1 Description of the Service Area (5.3.2a)

Remotes' distribution system serves 21 remote communities, each with specific needs. Nineteen of these sites have stand-alone generation systems. These communities are comparatively small and most do not have year-round road access. As a predominantly isolated and remote distribution system, Remotes serves very few customers spread over a large area.

Remotes' service territory is vulnerable to weather extremes owing to its geographical location in northern Ontario. The ability of staff to respond and repair facilities can be hampered by severe weather, especially with respect to cancelled or delayed flights or a plane's inability to land including when a flight has been attempted. These factors directly impact the reliability of the system.

Owing to Remotes predominantly overhead line distribution system, vegetation management is an important factor in managing reliability impacts and associated costs which may result from tree encroachment and contact with the overhead lines. Regular and routine vegetation management-related maintenance needs to be carried out in a dispersed service territory exposed to tree-related reliability impacts. Based on Remotes' historical performance (see Section 2.3.1.3.3), its vegetation management program has been effective at reducing the number of tree contact outages.

Economic growth in the communities has historically been and is expected to continue to be low. As shown in Table 1-3, a slight growth in the numbers of customers has been forecast in most communities. As customers plug in more devices, electricity usage is becoming more intensive. Table 4-10 presents the resultant peak load forecast for each community based on these factors.

3.2.2 Summary of System Configuration (5.3.2b)

3.2.2.1 Distribution

Since the communities serviced by Remotes are far apart and isolated, the distribution systems are separate and independent. The distribution voltage for these distribution systems ranges from 4.16 kV to 27.6 kV. There are approximately 242 kilometres of distribution lines which deliver the electricity to the 21 communities through 19 isolated distribution systems. Each distribution system consists of just one feeder. Table 3-1 summarizes the distribution system configuration.

Table 3-1: Summary of Remotes' Distribution System Configurations

Number of 27.6 kV systems	15
Number of 4.16 kV systems	4
Total number of distribution systems	19
Circuit km – 27.6 kV	220
Circuit km – 4.16 kV	22
Total km of distribution lines	242

The number of circuit kilometres in the communities anticipated to be added to Remotes' service area over the plan period cannot be readily estimated at this time.

3.2.2.2 Generation

Remotes owns 64 generators, of which 57 run on diesel fuel. They are rated between 60 kW to 1500 kW. Each station houses between two and four diesel generators. Most of the stations have three generators, sized to meet the loads at different times of the day. The generators are automated to run to maximize fuel efficiency by matching generator size to the electricity load of the community. Remotes handles over 17 million litres of diesel fuel each year, depending on the electrical demand of the communities.

Three hydroelectric generators and four wind turbines comprise the remaining generation. The capacities hydroelectric generators range from 150 to 225 kW, while the capacities of the wind turbines range from 10 to 60 kW.

Table 3-2 shows a complete list of Remotes' generators and GSUs by community.

Table 3-2: Generator and GSU Capacity

Community	Generation Unit	Generator Capacity (kW)	Engine Speed (rpm)	GSU Size (kVA)
Armstrong	A	725	1800	3 x 333
	B	725	1800	
	C	1100	1800	
Bearskin Lake	A	600	1800	3 x 500
	B	410	1800	
	C	1000	1200	
Big Trout Lake	A	600	1800	3 x 750
	B	1000	1800	
	C	1000	1200	
	T1	400	1800	
	WTG#1	60	-	
Biscotasing	A	60	1800	3 x 250
	B	96	1800	
	C	143	1800	
Deer Lake	A	1500	1200	1500

	B	635	1800	
	C	1050	1800	
	Hydel #1	225	-	
	Hydel #2	225	-	
Fort Severn	A	600	1200	3 x 333
	B	455	1800	
	C	1000	1200	
Gull Bay	A	450	1800	500
	B	180	1800	
	C	250	1800	
Hillsport	A	125	1800	3 x 50
	B	125	1800	
Kasabonika Lake	A	1000	1200	3 x 500
	B	1450	1200	
	C	600	1800	
	WTG#1	10	-	
	WTG#2	10	-	
	WTG#3	10	-	
Kingfisher Lake	A	455	1800	3 x 250
	B	600	1200	
	C	250	1800	
Lansdowne House	A	275	1800	3 x 333
	C	600	1800	
	D	600	1200	
Marten Falls	A	650	1200	3 x 250
	B	400	1800	
	C	250	1800	
Oba	A	65	1800	3 x 250
	B	65	1800	
	C	96	1800	
Sachigo Lake	A	635	1800	1250
	B	455	1800	
	C	1050	1200	
Sandy Lake	G1	1250	1200	4000
	G2	1250	1200	
	G3	1500	1200	
	G4	1000	1200	
Sultan	A	150	1800	3 x 200
	B	175	1800	
	Hydel #1	150	-	
Wapekeka	A	820	1200	3 x 333
	B	455	1800	
	C	410	1800	
Weagamow	A	600	1800	3 x 500

	B	725	1800	
	C	400	1800	
Webequie	G1	400	1800	1000
	G2	600	1200	
	G3	725	1200	
Total Diesel Generation		30,960		
Total Hydroelectric Generation		600		
Total Wind Generation Capacity		90		
Total Capacity		**31,650**		**22,746**

In addition, there are three generators in Wunnumin Lake, which Remotes is anticipating it will manage once this community is added to its service area.

3.2.3 Asset Demographics and Condition Information (5.3.2c)

The main categories of assets managed by Remotes are:

- Generators
- GSUs
- Poles
- Distribution Transformers

Table 3-3 shows Remotes' current asset count.

Table 3-3: Asset Counts for Major In-service Generation and Distribution Assets

Generators	GSUs	Poles	Distribution Transformers
64	47	4662	1138

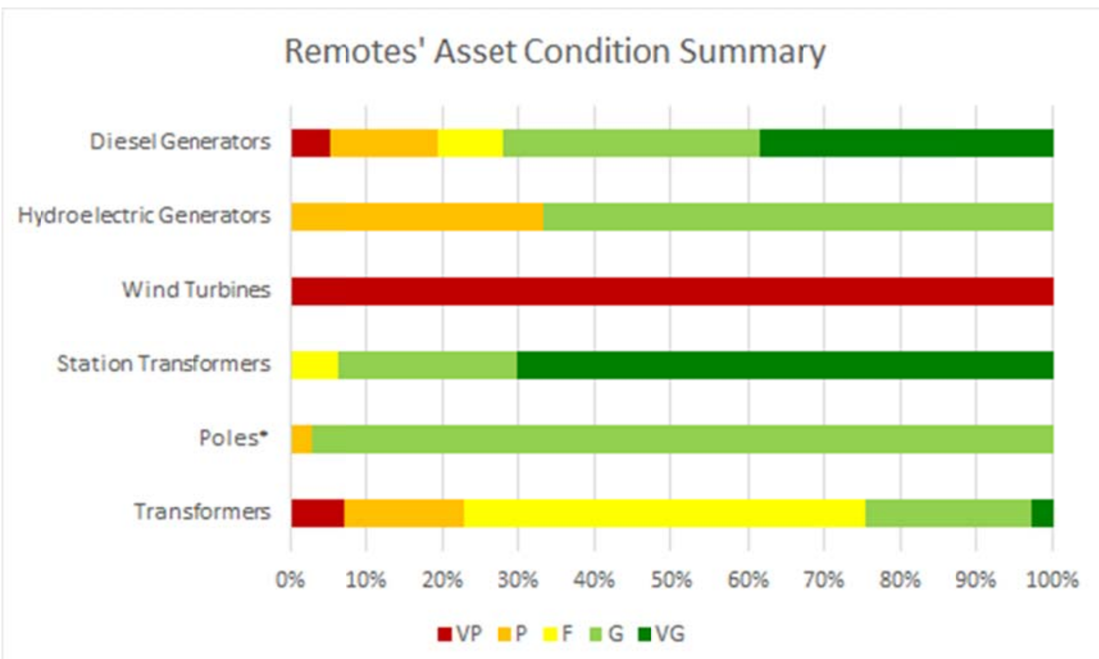
Asset Condition Assessment ("**ACA**") results are based on a consistent approach with the objective of applying a clear and unambiguous interpretation across the asset classes. Assets are divided into five, categories from Very Good to Very Poor based on the definitions in Table 3-4.

Table 3-4: Definition of Asset Conditions

Condition	Description	Requirements
Very Good (“**VG**”)	Some aging or minor deterioration of a limited number of components	Normal maintenance
Good (“**G**”)	Significant deterioration of some components	Normal maintenance
Fair (“**F**”)	Widespread significant deterioration or serious deterioration of specific components	Perform risk assessment; manage risk; consider replacement or refurbishment in five to ten years
Poor (“**P**”)	Widespread serious deterioration	Plan for replacement or refurbishment within the next five years
Very Poor (“**VP**”)	Extensive serious deterioration	Plan for immediate replacement or refurbishment

Figure 3-5 summarizes the condition of Remotes’ assets, as compiled on January 2, 2017. Note that poles have only have three condition categories: VP, P, and G.

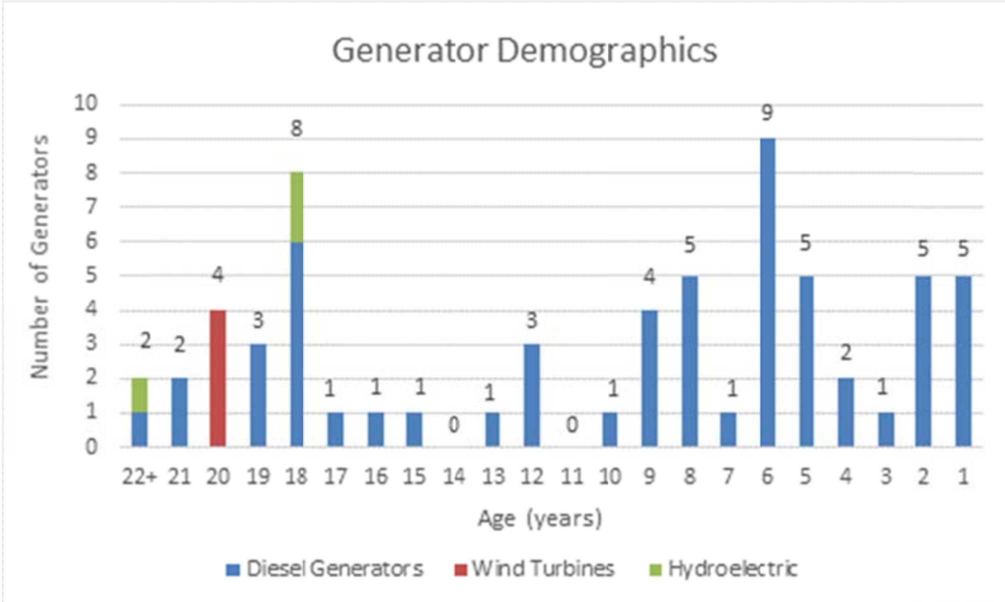
Figure 3-5: Summary of Remotes' Asset Condition Assessment



3.2.3.1 Generators

Remotes owns 64 generators, of which 57 run on diesel fuel. The remainder are three hydroelectric generators and four wind turbines. The age demographics for these generators are shown in Figure 3-6.

Figure 3-6: Age Demographics for Generators



The results of the ACA on Remotes' generators – based on engine-hours and operating experience – are summarized in Table 3-5. Table 3-6 presents the detailed in-service year, engine-hours, and condition of each unit. The condition scores of the wind turbines are driven by their ages, but these units are not economical to replace proactively and are run to failure. The conditions of the hydroelectric generators are based on inspections. The poor condition hydroelectric generator in Sultan is being repaired.

Table 3-5: Summary of the ACA for Generators

	VP	P	F	G	VG
Diesel Generators	3	8	5	19	22
Hydroelectric	0	1	0	2	0
Wind	4	0	0	0	0

Table 3-6: Generator In-service Year, Engine-hours, and Condition

Community	Generation Unit	In-service Year	Engine-hours	Condition
Armstrong	A	2015	7,297	VG
	B	2011	17,014	G
	C	1999	32,988	F
Bearskin Lake	A	2009	42,234	P
	B	2016	1,568	VG
	C	2000	12,508	VG
Big Trout Lake	A	1996	48,064	VP
	B	2010	37,146	P
	C	2005	46,082	G
	T1*	1999	6,431	VG

	WTG#1	1997	-	VP
Biscotasing	A	2012	4,423	VG
	B	2012	24,098	F
	C	2012	16,210	G
Deer Lake	A	2016	476	VG
	B	2016	3,382	VG
	C	2004	37,005	P
	Hydel #1	1999	-	G
	Hydel #2	1999	-	G
Fort Severn	A	1998	69,212	F
	B	2012	18,884	G
	C	2015	310	VG
Gull Bay	A	2009	12,056	G
	B	2011	31,757	F
	C	2011	10,450	VG
Hillsport	A	2007	43,474	P
	B	2001	64,034	VP
Kasabonika Lake	A	1998	73,818	P
	B	2015	923	VG
	C	2009	18,177	G
	WTG#1	1997	-	VP
	WTG#2	1997	-	VP
	WTG#3	1997	-	VP
Kingfisher Lake	A	2009	34,684	F
	B	1999	38,611	G
	C	2005	9,629	VG
Lansdowne House	A	2015	1,784	VG
	C	2014	16,246	G
	D	1999	11,909	VG
Marten Falls	A	1982	77,247	P
	B	2005	61,728	VP
	C	2016	18,708	G
Oba	A	2011	21,369	G
	B	2011	17,844	G
	C	2011	5,856	VG
Sachigo Lake	A	2013	11,567	VG
	B	2009	23,542	G
	C	2002	24,688	G
Sandy Lake	G1	2008	40,431	G
	G2	2008	23,256	VG
	G3	2013	6,942	VG
	G4	2008	45,627	G
Sultan	A	1999	45,271	P
	B	1998	45,194	P

	Hydel #1	1982	-	P
Wapekeka	A	1999	47,552	G
	B	2012	11,339	VG
	C	2015	7,657	VG
Weagamow	A	1996	9,487	VG
	B	2016	0	VG
	C	2008	14,596	G
Webequie	G1	2011	13,731	G
	G2	2011	28,943	G
	G3	2011	6,323	VG

**temporary unit*

Three of the diesel generators are in Very Poor condition: Big Trout Lake A, Hillsport B, and Marten Falls B. Marten Falls was last overhauled in February 2016 and its replacement is planned for when it reaches 80,000 engine-hours. Remotes is planning to procure a new generator for Big Trout Lake A in 2018 and to replace the unit in 2019. Hillsport B was last overhauled in 2016.

Eight of the diesel generators are in Poor condition: Bearskin Lake A, Big Trout Lake B, Deer Lake C, Hillsport A, Kasabonika A, Marten Falls A, Sultan A, and Sultan B. Bearskin Lake A was last overhauled in 2013. Remotes is planning to replace Big Trout Lake B in 2020. Deer Lake C is scheduled for replacement in 2021 and 2022. Hillsport and Sultan are both small communities that have temporary units that can be moved among the sites to manage the impact of an unplanned failure. A new generator to replace Kasabonika A will be procured in 2022. A new generator Marten Falls A has been procured and its replacement timing is under consideration.

Remotes also projects the number of engine-hours for each of its diesel generators for each year of the forecast period. Table 3-7 presents the year-end forecast for the years 2017 to 2022. A unit is highlighted in red on the year it exceeds the number of manufacturer-recommended engine-hours. Exceeding manufacturer-recommended hours increases the probability of a failure of the unit.

Table 3-7: Forecast Engine-hours for Diesel Generators

Community	Generation Unit	Forecast Engine-hours					
		2017	2018	2019	2020	2021	2022
Armstrong	A	12,142	16,961	21,781	26,601	31,421	36,240
	B	17,643	18,260	18,877	19,494	20,111	20,728
	C	36,552	39,811	43,069	46,328	49,587	52,846
Bearskin Lake	A	48,633	54,853	61,072	67,291	73,511	79,730
	B	2,827	4,080	5,332	6,585	7,837	9,090
	C	13,527	14,378	15,230	16,082	16,933	17,785
Big Trout Lake	A	50,774	53,321	55,868	58,415	60,962	63,509
	B	42,884	48,377	53,869	59,362	64,854	70,347
	C	49,039	51,814	54,588	57,363	60,137	62,912

Biscotasing	A	6,029	7,628	9,227	10,827	12,426	14,025
	B	30,430	36,534	42,638	48,742	54,846	60,950
	C	18,278	20,234	22,191	24,147	26,103	28,059
Deer Lake	A	914	1,319	1,723	2,128	2,533	2,938
	B	6,138	8,857	11,575	14,294	17,013	19,732
	C	42,731	48,188	53,646	59,103	64,561	70,018
Fort Severn	A	73,436	77,339	81,243	85,147	89,050	92,954
	B	23,398	27,913	32,427	36,942	41,456	45,970
	C	601	868	1,134	1,401	1,667	1,933
Gull Bay	A	13,144	14,040	14,937	15,833	16,729	17,625
	B	37,663	43,496	49,329	55,161	60,994	66,827
	C	12,446	14,364	16,282	18,200	20,118	22,036
Hillsport	A	48,445	53,272	58,100	62,928	67,756	72,583
	B	67,486	70,745	74,003	77,262	80,521	83,780
Kasabonika Lake	A	80,400	86,714	93,029	99,344	105,659	111,973
	B	1,770	2,554	3,338	4,122	4,906	5,690
	C	19,898	21,603	23,309	25,015	26,721	28,426
Kingfisher Lake	A	38,386	42,028	45,670	49,312	52,954	56,596
	B	42,751	46,607	50,463	54,319	58,175	62,031
	C	10,591	11,437	12,283	13,129	13,976	14,822
Lansdowne House	A	3,013	4,278	5,544	6,809	8,074	9,339
	C	23,372	30,170	36,967	43,765	50,562	57,360
	D	12,450	12,987	13,523	14,060	14,597	15,134
Marten Falls	A	81,172	84,779	88,385	91,991	95,597	99,204
	B	65,139	68,529	71,919	75,309	78,699	82,089
	C	52	75	98	121	144	167
Oba	A	26,736	32,103	37,470	42,836	48,203	53,570
	B	21,192	24,232	27,271	30,310	33,349	36,389
	C	6,137	6,388	6,638	6,889	7,139	7,390
Sachigo Lake	A	15,495	19,379	23,264	27,148	31,033	34,918
	B	26,041	28,538	31,035	33,532	36,029	38,526
	C	27,288	29,594	31,900	34,206	36,513	38,819
Sandy Lake	G1	45,674	50,622	55,571	60,519	65,468	70,416
	G2	27,413	31,370	35,327	39,284	43,241	47,198
	G3	9,080	11,118	13,156	15,194	17,233	19,271
	G4	4,798	9,597	14,395	19,193	23,991	28,790
Sultan	A	49,895	54,528	59,162	63,796	68,429	73,063
	B	48,289	51,299	54,310	57,321	60,331	63,342
Wapekeka	A	51,355	54,842	58,329	61,816	65,303	68,790
	B	13,216	15,075	16,933	18,792	20,650	22,508
	C	11,062	14,467	17,871	21,275	24,679	28,084
Weagamow	A	11,896	13,992	16,088	18,185	20,281	22,377
	B	5,515	7,958	10,401	12,844	15,286	17,729
	C	16,767	18,615	20,462	22,309	24,156	26,004

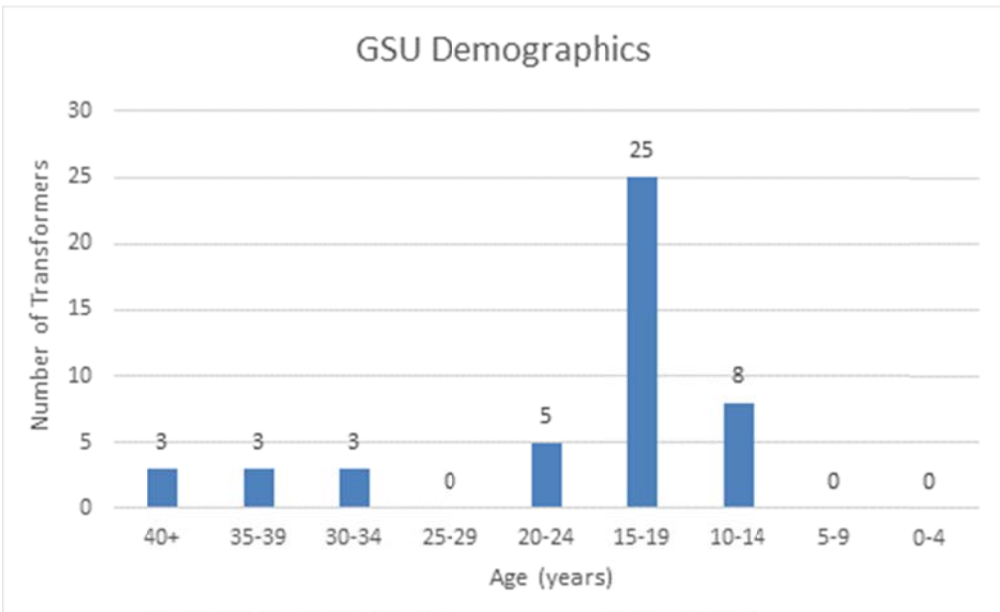
Webequie	G1	15,975	18,187	20,398	22,610	24,821	27,033
	G2	34,462	39,786	45,111	50,436	55,761	61,085
	G3	7,574	8,709	9,843	10,978	12,113	13,248

Many of these generators are already being managed based on the ACA results. In addition, a new generator for Biscotasing B will be procured in 2022, and a new generator for Gull Bay B will be procured and installed in 2021.

3.2.3.2 Generator Step-up Transformers

The age demographics for the in-service GSUs owned by Remotes are shown in Figure 3-7.

Figure 3-7: Age Demographics for GSUs



The ACA results of the in-service GSUs, determined using age-based health indices, are shown in Table 3-8.

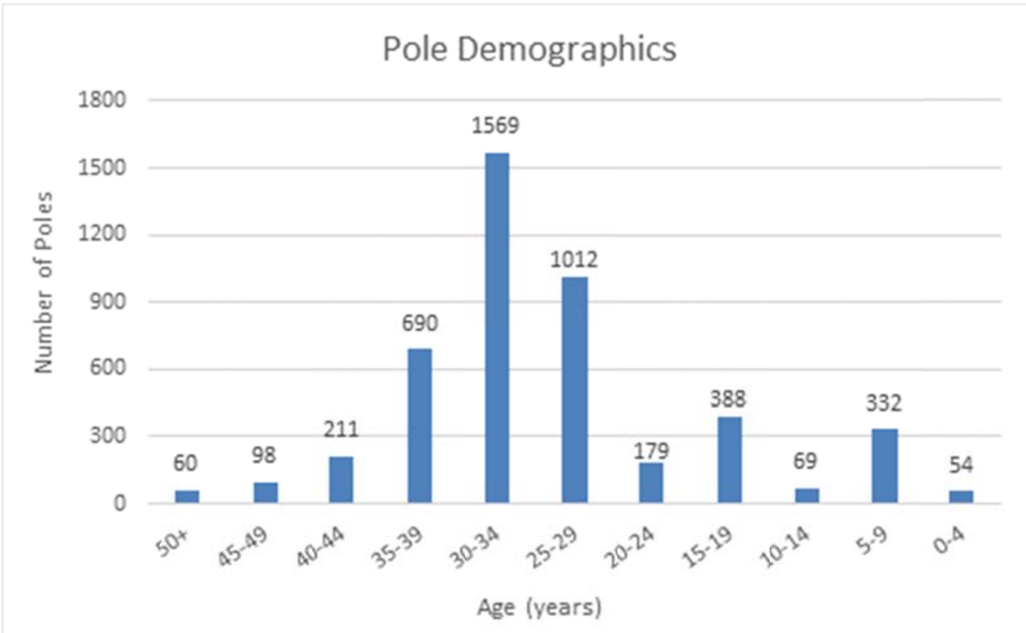
Table 3-8: Summary of the ACA for GSUs

VP	P	F	G	VG
0	0	3	11	33

3.2.3.3 Poles

Remotes owns 4,662 poles, a large portion of which are between 25 and 35 years old. The average pole age on the system is 28 years. Figure 3-8 presents the pole age demographics.

Figure 3-8: Age Demographics for Poles



Remotes' ACA for poles considers three categories:

- Very Poor – emergency replacement
- Poor – replace within five years
- Good – no replacement over next five years

An inspection was done on 3,977 of Remotes' wood poles in 2016 in every community. The inspections did not include the line from Armstrong to Collins, which is too expensive to patrol. The community of Collins does not have road or plane access and must be reached by train. The poles on this line are, therefore, replaced only on emergency response. The inspection included the following:

1. A hammer test is performed on each pole and values recorded as follows:
    a. OK (no action required)
    b. Hollow
2. A prodding test for surface rot or deterioration is performed on each pole and values recorded as follows:
    a. Light
    b. Medium
    c. Severe
3. A visual (condition) test is performed and values rated follows:
    a. Like New

b. Good
c. Fair
d. Poor
e. Very Poor

Other visual defects, for example woodpecker damage, are assessed as part of the inspection.

Table 3-9 summarizes the results of the ACA for poles. Over the next five years, Remotes is planning to replace 115 poles identified to be in poor condition. Additional pole replacements are typically required to maintain clearances.

Table 3-9: Summary of the ACA for Poles

Emergency	Replace Within 5 Years	No Replacement Within 5 Years
0	115	3,871

Based on the age demographics, a significant number of poles will be approaching end-of-life around the year 2040. Actual end-of-life assessment will be made based on condition. Remotes has kept this in mind for its long-term planning, but does not warrant any additional investment over the short term.

3.2.3.4 Distribution Transformers

Remotes currently owns about 1,138 distribution transformers. Figure 3-9 shows the age demographics for Remotes' distribution transformers and Table 3-10 presents the condition summary based on the age demographics.

Figure 3-9: Age Demographics for Distribution Transformers

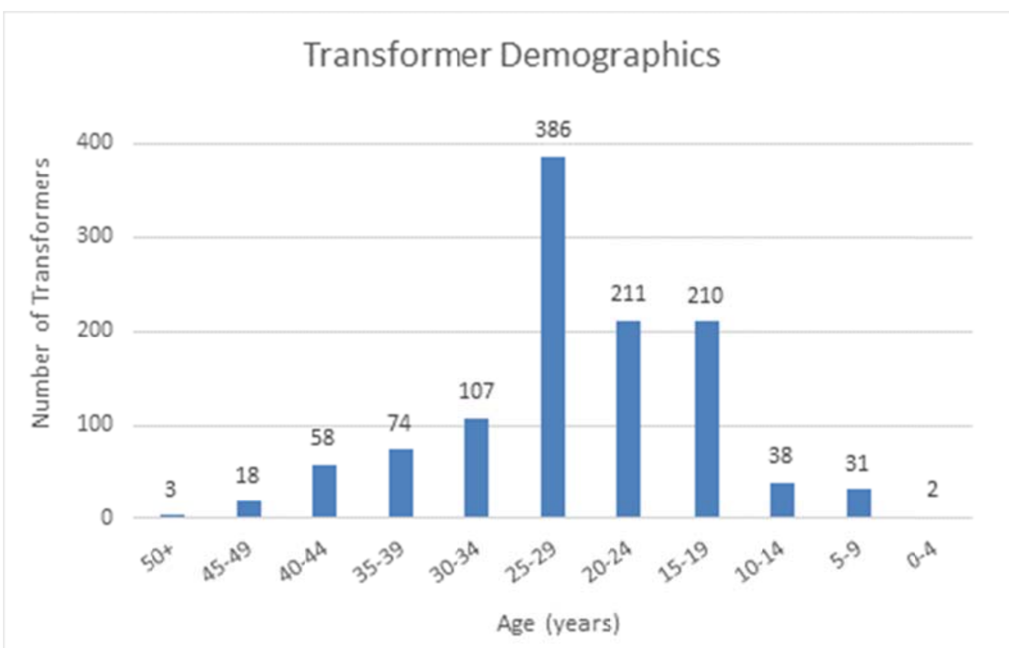


Table 3-10: Summary of the ACA Results for Distribution Transformers

VP	P	F	G	VG
79	181	597	248	33

3.2.4 System Utilization (5.3.2d)

As specific communities expand, Remotes' equipment is electrically loaded and stressed to higher levels. When loading and stresses exceed the equipment design capability and nameplate ratings, the equipment must be replaced with higher capacity equipment to ensure safety and reliability of supply. Table 3-11 illustrates the peak load in each community over the past four years, along with the community's station capacity and the connection limit (85% of the station capacity).

Table 3-11: Peak Load and Station Rating by Community

Community	Station Rating	Connection Limit	Peak Load (kW)			
			2013	2014	2015	2016
Armstrong	1450	1233	1021	1035	974	980
Bearskin Lake	1000	850	609	594	589	640
Big Trout Lake	1600	1360	1322	1395	1260	1277
Biscotasing	156	N/A*	145	170	166	146
Deer Lake	1795	1526	1357	1230	1220	1230
Fort Severn	1000	850	574	554	650	589
Gull Bay	430	366	334	316	288	325
Hillsport	125	N/A*	81	82	91	94
Kasabonika Lake	1600	1360	990	972	1106	1018
Kingfisher Lake	650	553	623	649	605	614
Lansdowne House	875	744	499	577	535	451
Marten Falls	650	553	489	493	494	475
Oba	120	N/A*	79	76	69	64
Sachigo Lake	1000	850	718	672	701	677
Sandy Lake	3050	2593	2576	2515	2370	2528
Sultan	150	N/A*	186	167	154	120
Wapekeka	865	735	643	628	621	595
Weagamow	1300	1105	1096	1025	966	979
Webequie	1000	850	625	615	647	633

**no load growth*

In communities where there is no load growth, the connection limit is not relevant planning criteria. These communities have a high number of seasonal customers and the peak loads often occur on holiday weekends.

Remotes existing feeder conductors have ample capacity for the loads in the communities. Most communities are served by 25 kV feeders with the remainder of smaller communities served by 4.16 kV systems. Given the small load sizes (below 3MW), the feeder conductors can carry loads several times larger than the current community peak load.

The generation station transformers are sized appropriately for the diesel generation station maximum load. Accordingly, the transformers are changed as part of the generation station upgrade process. The funding for the First Nation communities' generation station upgrades, which includes the replacement of the station transformers, is provided by the Federal government.

3.3 Asset Lifecycle Optimization and Risk Management (5.3.3)

This section presents Remotes' asset lifecycle optimization and risk management policies and practices.

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

Remotes' assets are managed based on a lifecycle management approach, which considers and balances asset performance, costs and associated risks during the asset service life to achieve asset optimization. Remotes investigated the relationship between capital spending and system O&M costs. Regardless of the capital spending, generator maintenance is required every 2,500 engine-hours. Due to the associated flight and fuel costs of this maintenance, there is no reduction to system O&M costs from capital investment.

3.3.1.1 Asset Replacement and Refurbishment Policies

Replacements and refurbishments of distribution assets include planned improvements and component replacements required to maintain the operation of distribution lines and associated equipment. They consist mainly of betterment projects and system upgrades, based on the asset age demographics and inspection results on asset condition in the community. The betterments include pole replacements, conductor restringing, and pole re-alignments.

Diesel generators are maintained as per manufacturer-published recommendations including complete overhauls after specified hours. The decision to replace or refurbish a generator is based on economics. Medium-speed (1800 rpm) units are rebuilt after 20,000 engine-hours, while low-speed (1200 rpm) units are overhauled between 32,000 and 40,000 engine-hours. After two overhauls, it is no longer economical to refurbish the generator as the life has been extended twice, parts may be obsolete and to improve fuel efficiency. Therefore, medium-speed generators are replaced after 60,000 engine-hours and low-speed generators are replaced between 96,000 and 120,000 engine-hours. Some units may be identified for earlier replacement subject to specific issues and asset condition discovered during its lifecycle. Replacement may be advanced or lengthened accordingly. A diesel generator replacement includes replacement of the auxiliary equipment and, often, replacement of the GSUs and breakers based on an assessment of their age, condition, and available capacity.

3.3.1.2 Maintenance Policies, Planning Criteria and Assumptions

Remotes' maintenance programs are defined for each asset listed below. In addition to the asset-specific programs, Remotes performs routine maintenance and inspections of various aspects and elements of the generating station.

Engines and Generators

Maintenance of engines and generators can be divided into planned and unplanned maintenance.

Planned maintenance of diesel generating units prevents premature equipment and system failures and contributes to service reliability. It includes all work performed on the diesel engine and associated generator in accordance with standard maintenance procedures as prescribed by the engine manufacturer. Intensive maintenance procedures are scheduled based on engine hours and vary from year to year. Inspections on engines are done every 5,000 hours.

Unplanned maintenance includes maintenance and repair of diesel generating units in response to trouble reports and equipment/component failures. This work is required to keep the station generating units available and operating to satisfy the rated station capacity required to meet community load. The program may identify the need for repairs/component replacement that would not be accomplished in the planned maintenance program.

Tank Farms

Planned maintenance of tank farms and associated equipment includes regular inspections of all bulk fuel storage tanks, transfer pumps, control circuitry, piping and valves in the tank farm and the fuel delivery kiosk. This work helps prevent premature failures and ensures the tank farm remains in working condition throughout its entire asset life. Tank farm inspections occur at all 19 stations. A review of outstanding fuel compliance audit findings is carried out to develop a long-term action plan. Corrective actions will be undertaken on a planned basis to address significant tank and fuel system defects as identified.

Unplanned maintenance of tank farms is a response to tank farm and fuel system problems and includes repair work required to keep the generating station fuel offload, bulk storage tanks and fuel transfer equipment in standard operating condition.

Remotes audits its fuel storage, fuel systems, fuel handling and record keeping in each community for compliance with federal and provincial regulations on a four-year cycle. Regulations related to fuel systems, storage and handling and record keeping are reviewed regularly and changes are incorporated into compliance reviews/audits. The reviews encompass the entirety of the fuel systems and identify opportunities for improvement, required testing or minor modifications, and areas of non-conformance. The audits look for items such as training, pipe corrosion, protection of pipes from vehicles, fire safety, and supports for above-ground tanks. When areas of non-compliance are noted, capital improvements to meet regulatory standards are scheduled based on condition of the assets and severity of the defect. In 2016, Remotes invited representatives of the provincial regulatory authority, the Technical Standards and Safety Authority, to participate in these compliance review/audits to improve the quality of the audit process and to improve its understanding of the regulatory requirements.

Facilities

Maintenance of facilities includes minor civil repair work required to maintain 19 generating station buildings, 14 staff houses, the Thunder Bay service center, fences, yards/sites which includes annual inspections and annual sampling of water facilities for all staff houses and generating stations. Planned maintenance of facilities ensures they may be used for projected asset life without the need for major refurbishments.

REG Maintenance

REG maintenance includes inspection and repair of equipment at REG facilities (water/wind powered) such as generating units and associated equipment. Maintenance is required to keep these stations and associated facilities in a standard operating condition. This program involves primarily planned inspection and maintenance of the hydro-electric stations located at Deer Lake and Sultan. The yearly maintenance involves hydraulic system maintenance, gear box maintenance, generator maintenance, switchgear and control maintenance, and turbine checks.

Unplanned maintenance may also be performed in response to issues identified during routine station operation. This can include, but is not limited to, the repairs and modifications of the water intake and outflow facilities, the generator units and auxiliary equipment, generator gears, communications equipment, and the station building/site.

Auxiliary Systems

Maintenance work on Generating Station auxiliary equipment is required to keep them in standard operating condition. The work is performed based on the results of diagnostic tests such as coolant sample analysis, along with normal cyclical maintenance, as part of an annual inspection or along with a major engine maintenance or overhaul procedure. Auxiliary equipment includes secondary heating, primary cooling, ventilation, overhead crane inspections, electrical, control and fire protection systems. Auxiliary systems maintenance includes, the main breaker cabinet, the station PLC, secondary heating, primary cooling, ventilation, pump controls, overhead crane inspections, station air compressors, DC batteries, station service electrical equipment and fire protection systems and all fuel system equipment and controls within the station.

GSUs

Remotes does not currently maintain its GSUs but is investigating which maintenance activities will be beneficial to manage the risk of these assets.

Distribution Assets

Maintenance on distribution assets is intended to ensure that the overall reliability of the distribution systems is maintained and improved, customer commitments are met, and all legislative and regulatory requirements are met. Data collected over past years identifies the required minor maintenance tasks in the communities.

Planned maintenance includes corrective and preventative line maintenance. The Distribution System Code requires that all local distribution companies patrol their distribution lines on a five-year cycle, to identify structural problems, damaged equipment and components that may cause a power interruption, as well as any hazards such as leaning poles, damaged equipment enclosures and vandalism. Preventative maintenance includes maintenance that is primarily cyclical in nature, including maintenance of equipment (load brake switches, electronic switches), as a means of reducing unplanned outages.

3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

The assets that make up the two major asset categories for generation and distribution are grouped into 15 different asset classes. These asset classes are further allocated to one of three asset priority categories: Priority 1 (P1); Priority 2 (P2); and Priority 3 (P3). The priorities reflect the criticality of the asset class to the Remotes' system, and include consideration of factors such as: public safety and employee health & safety; the importance of the asset to the sustained operation and reliability of the Remotes' system; electricity security; new equipment procurement lead times; regulatory and environmental requirements; and economics.

P1 assets represent the highest priority assets and are of high value and high risk to the business, receiving proportionally more of the total sustainment program funds. P2 assets are next in priority and, although they include high-risk assets, these generally require comparatively moderate program funds. Finally, P3 assets are lowest in priority with low program funds and lower risk to the business.

The allocation of the 15 asset classes into the three asset priority categories is indicated in Table 3-12. Capital expenditures identified in this DSP are selected and prioritized per this priority.

Table 3-12: Prioritization of Assets

	P1: High Priority	P2: Moderate Priority	P3: Low Priority
Generation	• Generation • Station Transformers • Fuel System & Fuel Inventory • Land Assessment & Remediation	• Generation Circuit Breakers • Protection & Control • Oil Containment	• Generation Station Service (AC/DC)
Distribution	• Overhead Line Sections • Wood Poles • Distribution Transformers • Right of Way Vegetation	• Switches & Fuses • Distribution: Operating Transformer Spares	• Meters

The continued performance of these assets is managed through capital investment and maintenance programs discussed in Section 3.3.1.2. Most communities have three diesel generators, rated for different capacities to optimize fuel efficiency. In case of a generator outage, the other generators can be used to mitigate the effects of the next contingency if a lengthy repair is required. Remotes keeps a spare transformer at each community to mitigate the impact of an outage. If a transformer fails, the community experiences a power interruption until the power can be switched to the spare – typically four hours.

4 Capital Expenditure Plan (5.4)

This section provides information on Remotes' capital investment program – derived from its asset management process – over the forecast period.

4.1 Summary (5.4.1)

4.1.1 Ability to Connect New Load (5.4.1a)

With population changes and more intensive use of electricity in remote communities, the overall number of new load connections for Remotes has increased. Due to the size of the communities served by Remotes, small changes in the electricity usage can have a large impact on the ability to connect new load.

Over the forecast period, capacity upgrades are planned in six of Remotes' diesel generation stations; Big Trout Lake, Deer Lake or Kasabonika, Fort Severn, Sandy Lake, Wapekeka and Weagamow. The peak load in these communities will surpass, or will be close to surpassing, 85% of the station rating in the next five years.

4.1.2 Capital Expenditures over the Forecast Period (5.4.1b)

Figure 4-1 depicts the net capital expenditures planned for each year of the forecast period. The investments are divided into system access, distribution system renewal, distribution system service, generation system renewal, generation system service, and general plant. There are planned expenditures in the system access category over the forecast period, but these projects and programs are 100% recoverable and, therefore, there is no forecast net spending. There are no planned expenditures that fall into the distribution system service category over the forecast period.

Figure 4-1: Net Capital Expenditure Forecast by Investment Category

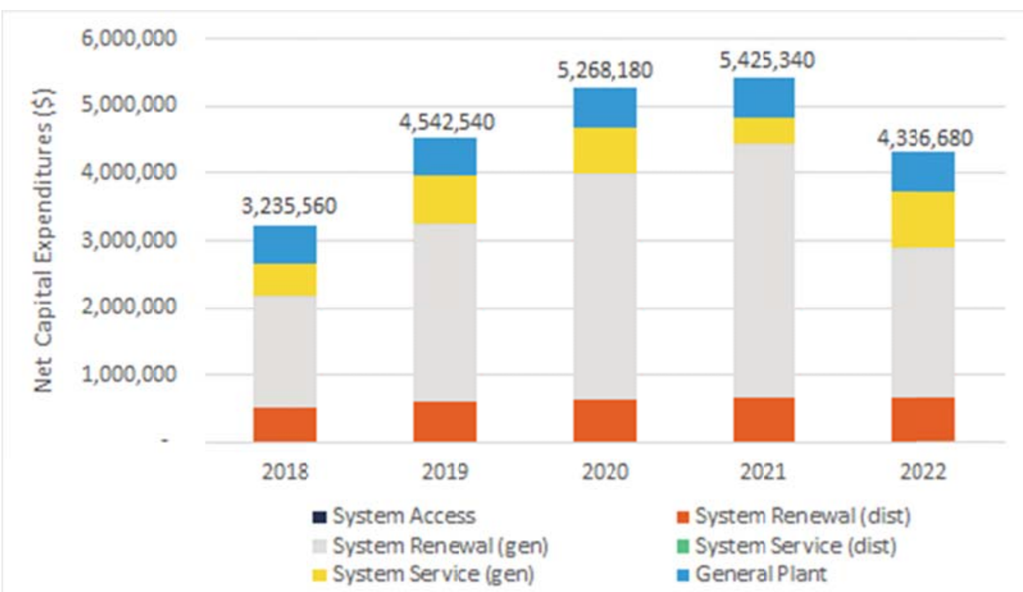


Table 4-1 presents the breakdown of capital expenditures on the distribution system, which includes system access and system renewal investments.

Table 4-1: Capital Expenditure Forecast by Investment Category - Distribution

Investment Categories	Forecast ($)				
	2018	2019	2020	2021	2022
System Access (gross)	912,000	1,065,000	1,121,000	1,143,000	1,166,000
Contributions & Removals	(912,000)	(1,065,000)	(1,121,000)	(1,143,000)	(1,166,000)
Net	0	0	0	0	0
System Renewal (gross)	772,000	899,000	947,000	965,000	983,000
Contributions & Removals	(250,240)	(290,360)	(304,120)	(311,160)	(313,320)
Net	521,760	608,640	642,880	653,840	669,680
System Service	0	0	0	0	0
Total Distribution (gross)	**1,684,000**	**1,964,000**	**2,068,000**	**2,108,000**	**2,149,000**
Contributions & Removals	**(1,162,240)**	**(1,355,360)**	**(1,425,120)**	**(1,454,160)**	**(1,479,320)**
Net	**521,760**	**608,640**	**642,880**	**653,840**	**669,680**

Table 4-2 presents the breakdown of capital expenditures on the generation system, which includes system renewal and system service investments.

Table 4-2: Capital Expenditure Forecast by Investment Category - Generation

Investment Category	Forecast ($)				
	2018	2019	2020	2021	2022
System Renewal (gross)	1,788,000	2,847,000	3,582,000	3,994,000	2,426,000
Contributions & Removals	(144,200)	(211,100)	(212,700)	(203,500	(205,000)
Net	1,643,800	2,635,900	3,369,300	3,790,500	2,221,000
System Service (gross)	5,853,000	6,852,000	6,392,000	5,412,000	5,810,000
Contributions & Removals	(5,348,000)	(6,126,000)	(5,717,000)	(5,021,000)	(4,962,000)
Net	505,000	726,000	675,000	391,000	848,000
Total Generation	**7,641,000**	**9,699,000**	**9,974,000**	**9,406,000**	**8,236,000**
Contributions & Removals	**(5,492,200)**	**(6,337,100)**	**(5,929,700)**	**(5,224,500)**	**(5,167,000)**
Net	**2,148,800**	**3,361,900**	**4,044,300**	**4,181,500**	**3,069,000**

Table 4-3 presents the breakdown of capital expenditures on the general plant investments.

Table 4-3: Capital Expenditure Forecast - General Plant

Investment Category	Forecast				
	2018	2019	2020	2021	2022
General Plant (gross)	565,000	572,000	581,000	590,000	598,000
Contributions & Removals	0	0	0	0	0
Net	565,000	572,000	581,000	590,000	598,000

4.1.3 Description of Investments (5.4.1c)

The following information provides a brief outline of the outputs of the asset management and capital expenditure planning process that have affected capital expenditures in the four investment categories.

4.1.3.1 System Access

System access investments include service cancellations, fixed price layouts, new customer connections, and service upgrades, all of which are initiated by customers. Gross expenditures are forecast based on historical levels and the actual spending each year depends on the number and nature of the customer requests received. System access investments over the forecast period are all 100% recoverable from customers and, as such, Remotes has not forecast net expenditures in this category.

4.1.3.2 System Renewal

Investments in the system renewal category comprise 73% of the forecast period net capital expenditures. These investments are driven by assets reaching the end of their service life as determined by the ACA, and include meter replacements, damage claims and storm damage restoration, pole replacements, system upgrades, and betterments. For the generation assets, system renewal work includes engine replacements, engine overhauls, diesel plant civil improvements, and fuel tank replacements.

4.1.3.3 System Service

System service investments includes solely investments related to generation equipment, which account for approximately 14% of the net capital expenditures over the forecast period. This work, however, constitutes a large part of Remotes' gross capital cost – equivalent to about 52%. This discrepancy is attributable to the fact that bulk of the work that falls into this category entails customer-requested generation project work that is fully funded by INAC. Projects comprising this category for the forecast period include generation station upgrades in Big Trout Lake, Deer Lake or Kasabonika (to be reassessed close to 2022), Fort Severn, Sandy Lake, Wapekeka, and Weagamow. Other investments in this category include generation station SCADA and PLC replacements, with upgrades planned in Weagamow and Kingfisher in 2018.

4.1.3.4 General Plant

Investments in the general plant category account for approximately 12% of the net capital expenditures and include housing improvements and other civil projects based on the building assessment (see Appendix H: Hydro One Remotes Roof Assessment Report) and investments into minor fixed assets.

4.1.4 List of Material Capital Expenditures (5.4.1d)

The budgeted costs of projects and programs above the materiality threshold ($283,000) are presented below for each investment category.

4.1.4.1 System Access

The only material program under the category of system access is new customer connections & service upgrades. The planned gross cost for this project can be seen in the table below, but the costs are 100% recoverable.

Table 4-4: Material System Access Projects over the Forecast Period

Project	2018	2019	2020	2021	2022
New Customer Connections & Service Upgrades	658,000	768,000	809,000	824,000	840,000
Contributions	(658,000)	(768,000)	(809,000)	(824,000)	(840,000)
Net	0	0	0	0	0

The year-over-year increase in the forecasted expenditures is driven by potential expansion of the service territory.

4.1.4.2 System Renewal

4.1.4.2.1 Distribution

Distribution system improvements are the only material project on the distribution side in the system renewal category. The forecast expenditures are illustrated in Table 4-5.

Table 4-5: Material Distribution System Renewal Projects over the Forecast Period

Project	2018	2019	2020	2021	2022
Distribution System Improvements	636,000	743,000	783,000	797,000	813,000
Contributions & Removals	(216,320)	(253,160)	(265,960)	(271,640)	(273,560)
Net	419,680	489,840	517,040	525,360	539,440

This work varies year to year based on the size, nature, and volume of joint use activity and asset degradation. The yearly increase can be accounted for by the expansion of the service territory.

4.1.4.2.2 Generation

Engine replacements and engine overhauls make up a substantial part of system renewal investments. The gross and net expenditures for replacements and overhauls are shown in Table 4-6.

Table 4-6: Engine Replacements and Overhauls over the Forecast Period

Project	2018	2019	2020	2021	2022
Engine Replacements	-	-	-	1,317,000	1,318,000
Big Trout Lake A Replacement	767,000	1,423,000	-	-	-
Big Trout Lake B Replacement	-	-	1,425,000	-	-
Removals (10%)	(76,700)	(142,300)	(142,500)	(131,700)	(131,800)
Net	690,300	1,280,700	1,282,500	1,185,300	1,186,200
Engine Overhauls	675,000	688,000	702,000	718,000	732,000
Removals (10%)	(67,500)	(68,800)	(70,200)	(71,800)	(73,200)
Net	607,500	619,200	631,800	646,200	658,800
Total (net)	**1,297,800**	**1,899,900**	**1,914,300**	**1,831,500**	**1,845,000**

Other material projects in this category include tank replacements and diesel plant civil improvements. The expenditures are shown in Table 4-7.

Table 4-7: Fuel Tank Replacements and Diesel Plant Civil Improvements

Project	2018	2019	2020	2021	2022
Sultan Bulk Tank Farm	-	-	-	274,000	-
Armstrong Day Tank	-	-	438,000	-	-
Big Trout Bulk Tanks & Day Tanks	-	-	657,000	1,317,000	-
Oba Bulk Tank	-	383,000	-	-	-
Diesel Plant Civil Improvements	346,000	353,000	360,000	368,000	376,000
Total	**346,000**	**736,000**	**1,455,000**	**1,959,000**	**376,000**

4.1.4.3 System Service

4.1.4.3.1 Distribution

There are currently no planned projects on the distribution side of the system service category.

4.1.4.3.2 Generation

Table 4-8 shows the forecast generation projects in the system service category that meet the materiality threshold. Most of them are generation station upgrades. In addition to capacity upgrades in Big Trout Lake and Wapekeka, an integration of controls for these two generation stations is planned. All the station upgrades are (100% recoverable from INAC. Other generation projects in the system service category include controls and SCADA upgrades at the generating stations.

Table 4-8: Material Generation System Service Projects over the Forecast Period

Project	2018	2019	2020	2021	2022
Generator Upgrades					
Big Trout Lake - Wapekeka Upgrade & Connection	2,149,000	3,252,000	1,364,000	-	-
Deer Lake or Kasabonika	-	-	-	1,364,000	4,962,000
Fort Severn	-	-	3,042,000	3,657,000	-
Sandy Lake	367,000	881,000	1,311,000	-	-
Weagamow	2,832,000	1,993,000	-	-	-
Contributions	(5,348,000)	(6,126,000)	(5,717,000)	(5,021,000)	(4,962,000)
Net	0	0	0	0	0
Controls/SCADA Upgrades					
Sandy Lake & Biscotasing - Bulk Tank Platform & Controls	-	-	-	-	495,000
SCADA & PLC Replacements & High-Speed Internet	505,000	726,000	675,000	391,000	353,000
Total (net)	**505,000**	**726,000**	**675,000**	**391,000**	**848,000**

4.1.4.4 General Plant

Table 4-9 lists the planned expenditures in the general plant category over the forecast period. Programs in this category include housing improvements, storage buildings, miscellaneous civil projects, and minor fixed assets. None of these programs exceed the materiality threshold.

Table 4-9: General Plant Spending over the Forecast Period

	2018	2019	2020	2021	2022
General Plant	565,000	572,000	581,000	590,000	598,000

4.1.5 Information pertaining to the Regional Planning Process (5.4.1e)

The 2014 draft Remote Community Connection Plan is a business case which informed a July 29, 2016, Order-in-Council from the Provincial Government. This order confirms the intention for the project to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes and at least two are expected to be served by Remotes in the future. While this will not affect investments in the communities over the five-year period of this DSP, it has affected the investments INAC makes in generation assets, and it is expected that the construction activities of this new transmission line will affect Remotes planning considerations over the medium-to-long term. The order from the Minister of Energy is included as Appendix C: Order-in-Council from the Minister of Energy.

Since the Remote Community Connection Plan is still in its draft form, the connection dates for the communities served by Remotes are not firmly established at this time. Furthermore, there is the possibility of retaining Remotes' diesel generation fleet for community electricity supply backup, as per the diesel backup study (see Section 2.2.1.3.4). Based on the need to continue to provide customers with a reliable supply of electricity in the near term and the possibility of retaining the generator fleet to serve as backup power supply, Remotes' generator replacement and overhaul programs have not been affected by the Regional Planning Process.

Regional electricity infrastructure requirements have been accounted for in Remotes' generator upgrade plan. In anticipation of the new transmission lines reaching the communities of Big Trout Lake (Kitchenuhmaykoosib Inninuwug) and Wapekeka, a new distribution line is being constructed as an integrated, cost-effective approach to increase the capacity of both communities, as well as improving the robustness of the electricity supply. The new distribution line will be required to connect the communities to the new transmission line. The peak load in Weagamow is forecast to reach the connection limit in 2019; therefore, Remotes intends to proceed with the generator upgrade in this community. The project plan accounts for the anticipated future connection of this community and tank storage upgrades have been foregone as a more near-term approach due to the long-term uncertainties. The peak load in Sandy Lake is forecast to reach the connection limit in 2018, so the generator upgrade project in Sandy Lake will also proceed.

4.1.6 Customer Engagement Activities (5.4.1f)

Remotes listens to its customers and, in First Nations communities, works closely with Band Councils to help them meet community electricity needs and preferences. Remotes regularly communicates and meets with their customers throughout the year. The focus of communication efforts is with First Nation communities that comprise approximately 90% of the customer base. Each community has a direct contact with Remotes. Communication takes place in many forms including email, phone, letter, conference call, or face-to-face meetings. Remotes' customers have asked for more face-to-face meetings, so Remotes has increased the frequency that it visits the communities and has started including its customer service staff in community meetings.

Funding arrangements with INAC also require Remotes to meet with INAC and local First Nations to plan capital projects. Since 2009, the Director of Remotes has had specific performance targets to meet face-to–face at least eight times per year with First Nation Band Councils or Tribal Councils to discuss areas of mutual concerns and to maintain open lines of communication. Other staff also meet with First Nation Band Councils or Tribal Councils regularly to discuss topics such as:

All Communities – Normal Activities & Communication

- Connections, collections, work in community
- Customer renewables
- Insurance
- Snowplowing
- Gravel
- Planned housing
- Winter road tolls
- Equipment rental
- Temporary labour
- Charity and sponsorship
- Meter reading
- Operator contracts
- Disconnections
- Winter road conditions
- Third party staff house use
- Environmental - site
- Forestry line clearing
- Community emergencies/disruptions
- Public Safety
- Community energy overview, load, peak, assets
- Energy forecast and housing, community development

Communities Not Served by Remotes

- Our services, asset assessment and condition, transferring to Hydro One Networks Inc.
- Grid line development

Communities No Longer Served by Remotes

- Remediation

Collins/Namaygoosisagagun First Nation (Armstrong Area)

- Trouble response

Whitesand First Nation (Armstrong Area)

- First Nation biomass renewable project (including IESO and CIA package), technical and operational meetings
- Distribution expansion and ownership
- Reindeer rates
- Load growth and peak
- Emissions

Bearskin

- First Nation fuel purchase – winter road
- Generation upgrades
- Heat traces
- Remediation of old site (bio cell)
- Reliability
- Renewables
- Third party financing

Big Trout/Kitchenuhmaykoosib Inninuwug

- First Nation fuel purchase – winter road
- Connection restrictions
- Proposed line between Big Trout Lake and Wapekeka
- Long term payment plan
- Leaning poles
- Community sub-contractor concerns
- Fuel truck operations – kiosk spill
- Windmill production
- Urgent fuel needs
- Outage - lengthy
- University research project
- Loaned fuel
- Arena usage
- Fuel wagon delivery
- Forestry concerns, tree replanting

Deer Lake

- Generation upgrades
- School solar
- Shoulder Blade falls hydel production and operation
- Community restrictions
- Third party financing
- Long term payment plan
- Housing connections – urgent
- Conservation and demand management
- Funding support
- Long term operating agreement – Shoulder Blade
- Potential fuel farm

Fort Severn

- First Nation fuel purchase – winter road and barge
- Community solar project – large scale installation
- Renewable projects – roof mounted
- Letters of funding support
- Secondary heat – water treatment plant
- Fuel quality
- Generation upgrade
- Generation trouble response
- Load restrictions
- New school
- Wind turbine – old and proposed
- Old Hydro house – sale
- Renewable study support
- Conservation and demand management
- Site expansion

Gull Bay

- Consumption
- Solar – micro grid project (OPG)
- Hydroelectric discussion
- Emissions
- Rates
- Rate relief
- Land permits
- Future diesel upgrade

Kasabonika

- Generation upgrades
- Damage claim
- Connection restrictions
- Fibre
- Renewable research
- Petrokas tank farm upgrades
- Fuel contract award
- Gravel misuse
- Wind turbine production
- Christmas lights
- Petrokas operation and maintenance
- Noise complaint – wind
- New store

Kingfisher

- Generation upgrades
- Connection restrictions
- Site environmental
- Kingfisher preferred fuel suppliers

- Solar installation
- Yard expansion
- Surplus equipment sale
- Recycling oil

Lansdowne

- Generation upgrades
- Connection restrictions
- Community centre load impacts

Marten Falls

- Long term arrears
- Connection restrictions
- Outages
- Account set up
- Fuel sale – third party
- Winter road delivery and logistics

Sachigo

- First Nation fuel purchase – winter road
- Generation upgrades
- Flights to Sachigo
- First Nation pipe leak
- Third party financing letter
- First Nation tank farm design and operation
- Timing of collections trip

Sandy Lake

- First Nation fuel purchase – winter road
- Low fuel levels
- Financing letters of support
- First Nation tank farm upgrades and operations
- Duck River Hydroelectric development
- Old Hydro house
- Loaned fuel

Wapekeka

- Generation upgrades
- Connection restrictions
- Proposed line between Big Trout Lake and Wapekeka
- Technical diesel generation station study
- School fire and replacement
- Long term payment plan
- Fawn River Hydroelectric
- Wapekeka Solar
- Community fuel deliveries

Weagamow / North Caribou First Nation

- Generation upgrades
- Connections restrictions
- Proposed solar project
- Streetlight retrofit
- Conservation and demand management
- Temporary power agreement and operation
- Emergency response
- Site environmental
- Christmas lights
- Trailer extension
- House permit
- Certificate of Approval and Environmental Compliance Approval ownership
- Tank farm project
- Road development
- Site expansion

Webequie

- Remediation of old site
- Long term payments and arrears
- Public safety
- Solar connection
- Sale of old Hydro house
- Airport operations

Other First Nation Partners (Tribal Councils)

These partners include Matawa First Nations Management, Keewaytinook Okimakanak, Shibogama First Nations Council, Nishnawbe Aski Nation, Windigo First Nations Council, and Independent First Nations Alliance.

- Project or issues supporting specific communities above.

4.1.7 System Development over the Forecast Period (5.4.1g)

System development over the forecast period is presented with respect to load and customer growth, smart grid, and REG accommodation.

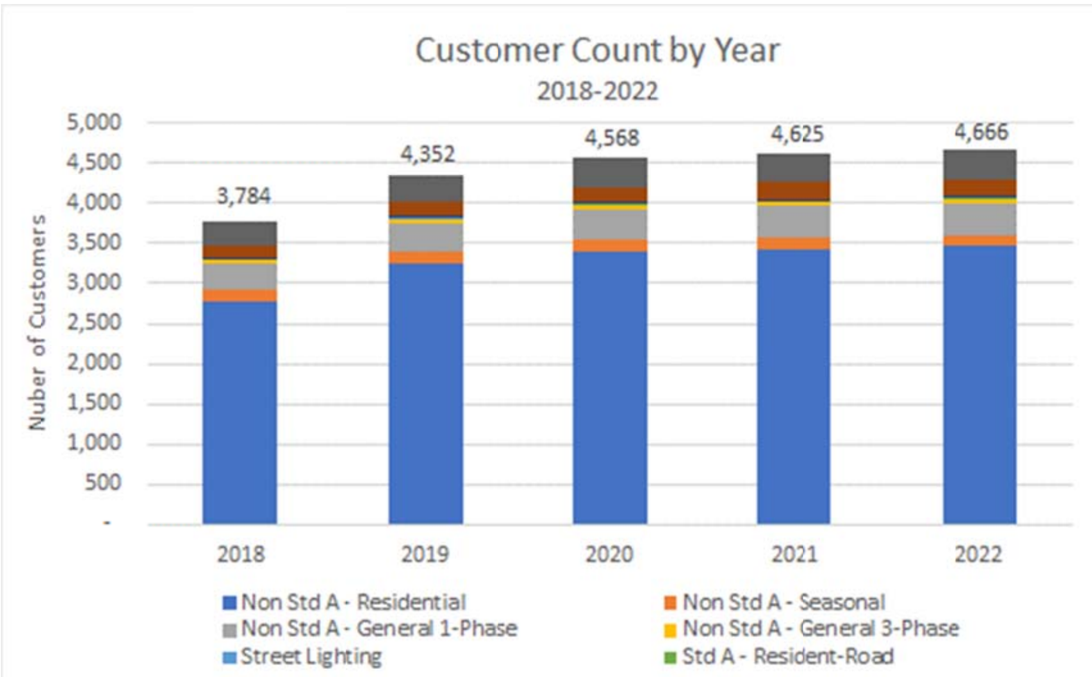
4.1.7.1 Load and Customer Growth

Remotes' service area is expected to expand to include three new communities during the forecast period. One of these, Cat Lake, is already connected to the Hydro One Networks Inc. transmission system in northwestern Ontario; therefore, Remotes will only be responsible for power distribution in this community. This transfer is planned for 2018, is contingent upon an agreement with the community, and will result in a customer increase of 111. Watay Power is planning to build a distribution line to the community of Pikangikum in 2017 to 2018, in advance of other community connections. If the line is built, then Remotes will operate the distribution assets in the community, with distribution lines servicing about

2,300 people and 532 customers. Remotes assessed the generation and distribution assets in Wunnumin Lake. With limited capital investments, Remotes could safely and reliably operate the distribution and generation assets in the community. A transfer of service to Remotes is planned for 2020, prior to the community's connection to the grid, adding 176 new customers to Remotes service territory.

Remotes' total customer growth is shown in Figure 4-2. The annual load growth in Remotes' existing communities is forecasted to be around 3.5%.

Figure 4-2: Remotes' Customer Growth over the Forecast Period



Remotes uses historical load to predict future annual increase in each community. The predicted increase is then used to calculate future peak load. Table 4-10 summarizes future annual increase, peak load for 2017-2022 and current station rating and connection limit by community. The community load is highlighted in yellow where it is forecast to exceed the connection limit and highlighted in orange where it is forecast to exceed the station capacity.

To account for the load growth, Remotes has scheduled six generating station upgrades in the next five years in Big Trout Lake, Wapekeka, Sandy Lake, Weagamow, Fort Severn, and either Deer Lake or Kasabonika, depending on the actual load growth and the availability of INAC funding.

Table 4-10: Forecast Peak Load by Community

Community	Future Annual Increase	Peak Load (kW) 2017	2018	2019	2020	2021	2022	Station Rating (kW)	Connection Limit (kW)
Armstrong	3.0%	1035	1066	1098	1131	1164	1199	1450	1233
Bearskin Lake	2.5%	614	629	645	661	678	695	1000	850
Big Trout Lake	4.0%	1381	1436	1493	1553	1615	1680	1600	1360
Biscotasing	0.0%	100	100	100	100	100	100	156	N/A*
Deer Lake	4.0%	1340	1394	1449	1507	1568	1630	1795	1526
Fort Severn	6.0%	689	730	774	821	870	922	1000	850
Gull Bay	1.0%	314	317	320	324	327	330	430	366
Hillsport	0.0%	80	80	80	80	80	80	125	N/A*
Kasabonika	4.5%	1156	1208	1262	1319	1378	1440	1600	1360
Kingfisher Lake	4.0%	652	678	705	734	763	793	1055	897
Lansdowne	5.0%	584	613	644	676	710	745	875	744
Marten Falls	1.5%	501	509	517	524	532	540	650	553
Oba	0.0%	75	75	75	75	75	75	120	N/A*
Sachigo Lake	3.0%	731	753	775	799	823	847	1000	850
Sandy Lake	2.5%	2535	2598	2663	2730	2798	2868	3050	2593
Sultan	0.0%	130	130	130	130	130	130	150	N/A*
Wapekeka	3.0%	651	670	691	711	733	755	865	735
Weagamow	3.0%	1062	1094	1127	1160	1195	1231	1425	1211
Webequie	2.0%	660	673	687	700	714	729	1000	850

**no load growth*

4.1.7.2 Smart Grid Development

Remotes' investment plan includes the installation of Viper switches on the distribution system to improve reliability and cold-load pickup. SCADA and PLC upgrades at Remotes' generating stations will also facilitate a more dynamic and responsive grid operation, providing improved acquisition and alarm handling capabilities from a remote location. In some situations, this will allow for remote monitoring, control and restoration of power after an interruption.

4.1.7.3 REG Accommodation

A biomass project is being developed in Whitesand under Remotes' REINDEER program in cooperation with the IESO. If the project develops as planned, it is anticipated that electrical output could displace electrical load within the community and that settlement would be based on the avoided cost of diesel fuel in that community. No project timeline has yet been developed for the construction of this project.

Another project, supported by federal and provincial grants, is currently being developed by Fort Severn First Nation and private sector developers. Remotes' role in this project is to ensure the ongoing reliability and stability of the existing microgrid and to ensure that the project can be integrated into the existing generation system. The project is staged, with 40 kW of net-metered solar installed to date. When fully installed, the project will qualify for Remotes' REINDEER program and, consistent with that program, Remotes will pay for the electricity produced based on the avoided cost of diesel fuel.

A 360-kW solar/battery microgrid project, supported by provincial grants, is also planned for Gull Bay. The project is currently in the very early stages. It is anticipated that the project will also qualify for Remotes' REINDEER program and that settlement will also be based on the avoided cost of diesel fuel in that community.

4.1.8 Customer Preference, Technological Opportunity, Innovation (5.4.1h)

A list and brief description of projects/programs planned in response to customer preferences (e.g. data access and visibility, participation in distributed generation, load management); to take advantage of technology-based opportunities to improve operational efficiency, asset management, and the integration of distributed generation and complex loads; and to study or demonstrate innovative processes, services, business models, or technologies is provided below.

4.1.8.1 Customer Preferences

Distribution system investments in the system access category are initiated by customers. The total capital costs of these programs are shown in Table 4-11.

Table 4-11: Customer-requested Distribution Projects

Project	2018	2019	2020	2021	2022
Service Cancellations	148,000	173,000	182,000	186,000	190,000
Fixed Price Layouts	106,000	124,000	130,000	133,000	136,000
New Customer Connections & Service Upgrades	658,000	768,000	809,000	824,000	840,000
Total (gross)	**912,000**	**1,065,000**	**1,121,000**	**1,143,000**	**1,166,000**
Contributions & Removals	(912,000)	(1,065,000)	(1,121,000)	(1,143,000)	(1,166,00)
Total (net)	**0**	**0**	**0**	**0**	**0**

Generator upgrades are also customer-requested. Table 4-12 lists the total capital cost of the generator upgrades planned over the forecast period.

Table 4-12: Customer-requested Generation Projects

Project	2018	2019	2020	2021	2022
BTL-Wapekeka Upgrade & Connection	2,149,000	3,252,000	1,364,000	0	0
Deer Lake or Kasabonika	0	0	0	1,364,000	4,962,000
Fort Severn	0	0	3,042,000	3,657,000	0
Sandy Lake	367,000	881,000	1,311,000	0	0
Weagamow	2,832,000	1,993,000		0	0
Total (gross)	**5,348,000**	**6,126,000**	**5,717,000**	**5,021,000**	**4,962,000**
Contributions & Removals	(5,348,000)	(6,126,000)	(5,717,000)	(5,021,000)	(4,962,000)
Total (net)	**0**	**0**	**0**	**0**	**0**

4.1.8.2 Technology-based Opportunities

Planned investments into PLC and SCADA systems, as well as fuel tank controllers will improve operational efficiency and asset management capabilities. These investments entail communication upgrade, SCADA hardware and software upgrade, and PLC hardware and software upgrade. Table 4-13 lists the planned expenditures over the forecast period.

Table 4-13: Projects in response to Technology-based Opportunities

Project	2018	2019	2020	2021	2022
SCADA & PLC Replacements & High-Speed Internet	505,000	726,000	675,000	391,000	353,000
Sandy Lake & Biscotasing - Bulk Tank Platform & Controls	-	-	-	-	495,000
Total	**505,000**	**726,000**	**675,000**	**391,000**	**848,000**

4.1.8.3 Innovative Processes, Services, Business Models, or Technologies

Remotes has not planned any projects/programs to study or demonstrate innovative process, services, business models, or technologies.

4.2 Capital Expenditure Planning Process Overview (5.4.2)

4.2.1 Planning Objectives, Assumptions, and Criteria (5.4.2a)

Business planning is performed annually and focuses on the development of a six-year plan. The current plan contains the detailed 2017 budget and the 2018 to 2022 forecast. The business plan incorporates the same strategic objectives outlined in Section 3.1.1.

To facilitate the preparation of the business plan, an economic outlook is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, and cost rates for benefits.

Remotes manages its diesel generating stations by limiting the peak load at the station to 85% of the station's rating (known as the connection limit). This threshold allows for consumption growth as existing customers connect more devices to the grid without compromising the ability to supply power during peak load. When the peak load in the community nears the connection limit and additional load growth is forecast, the station upgrade planning process commences. In communities where there is no load growth, the connection limit is not relevant planning criteria. These communities have a high number of seasonal customers and the peak loads often occur on holiday weekends.

Remotes currently owns REG facilities in Big Trout Lake (wind), Deer Lake (hydroelectric), Kasabonika (wind), and Sultan (hydroelectric). New facilities are planned in Fort Severn (net-metered solar) and Gull Bay (solar/battery). A biomass generating station is planned in Whitesand. Customers in Big Trout Lake and Wapekeka have requested an additional 67.5 kW of community-owned solar generation, to be placed on appropriate non-Standard A customer accounts. Remotes' customers also have the ability to install their own REG facilities and sell power to Remotes; 15 small customer-owned solar net metering projects are now in service.

4.2.2 Non-Distribution System Alternatives to Relieving Capacity (5.4.2b)

Remotes' service areas do not include large industrial customers who offer the most potential for effective demand response and other peak shaving programs. Remotes engages in CDM activities as described in Section 1.4.4; however, Remotes' customers have expressed a disinterest in CDM and a preference towards REG. Further customer engagement has emphasized electricity availability rather than CDM (see Appendix E: 2016 Customer Workshop). Therefore, when relieving system capacity and operational constraints, Remotes considers alternatives on both the distribution and generation side, including REG investments, as well as the planned transmission system connection.

4.2.3 Processes, Tools, and Methods (5.4.2c)

The typical annual business planning process consists of six stages:

1. Strategic direction and goals established;
2. Risk review and investment requirements;
3. Confirmation of strategic direction and goals with Hydro One Inc.;

4. Development of economic outlook and forecast assumptions;
5. Development of plans and work programs; and
6. Approval by Hydro One Inc. Senior Management and Board of Directors.

Capital expenditures are identified based on Remotes' asset management process (as described in Section 4.2.3). Annually, required investments are determined based on asset condition, engine hours, load growth and external factors such as INAC funding and winter roads.

Several projects/programs are treated as non-discretionary since they are customer-initiated and fully recoverable. These include:

- Generator upgrades;
- New customer connections and service upgrades;
- Fixed price layouts; and
- Service cancellations.

Other investments are then ranked against seven risk categories: customer/reliability, regulatory, financial, operational efficiency, environmental, safety, and reputation. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and considers levels of investment and associated risk mitigation. A final investment plan is then endorsed and confirmed by the Hydro One Inc. senior management team.

The decision to defer a project due to limited resources is made based on risk. Typically, civil projects, motor controller upgrades, and PLC upgrades are deferred when required.

4.2.4 Customer Engagement (5.4.2d)

4.2.4.1 Customer Acceptance and Feedback

Generation upgrade projects are championed by the community in need of capacity. When Remotes has determined that a generation upgrade is needed, it approaches the community to inform them and the community must apply to INAC for funding. If the community decides not to support the upgrade, then they would not apply for funding and the project would not go through. Therefore, generation upgrade projects identified in this DSP are supported by the communities in which the upgrades will occur.

Remotes revised its capital processes in response to feedback from its customers and a decreasing availability of funding from the federal government. In the past, there were ongoing connection constraints due to an unavailability of funding from INAC. Remotes' new generation upgrade process reduces both the cost and time required for generation upgrades and has reduced the number of communities with connection restrictions.

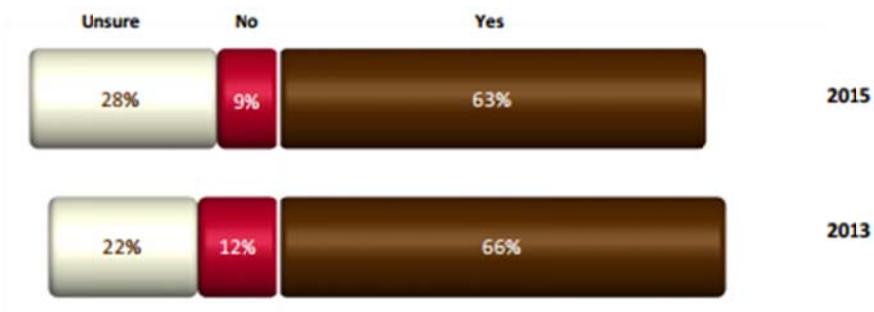
4.2.4.2 Customer Surveys

In 2015, Viewpoints Research conducted its most recent telephone survey of 205 residential, business, and government-supported organization customers served by Remotes. Many of the questions in this survey have been tracked from earlier customer surveys administered about every two years since 2003. In addition to the customer satisfaction results discussed in Section 2.3.1.1, other findings of the customer survey which reflect customer needs, priorities, and preferences include improved reliability, handling of customer contact, ways to improve service, helpfulness of staff, and environmental protection. The complete customer survey is attached as Appendix D: Customer Satisfaction Survey Results.

Environmental Protection

Sixty-three per cent of respondents said Remotes takes environmental protection in the community seriously down three per cent since 2013. Nine per cent said Remotes does not take it seriously, also down three per cent since the previous survey. Twenty-eight per cent of respondents were unsure.

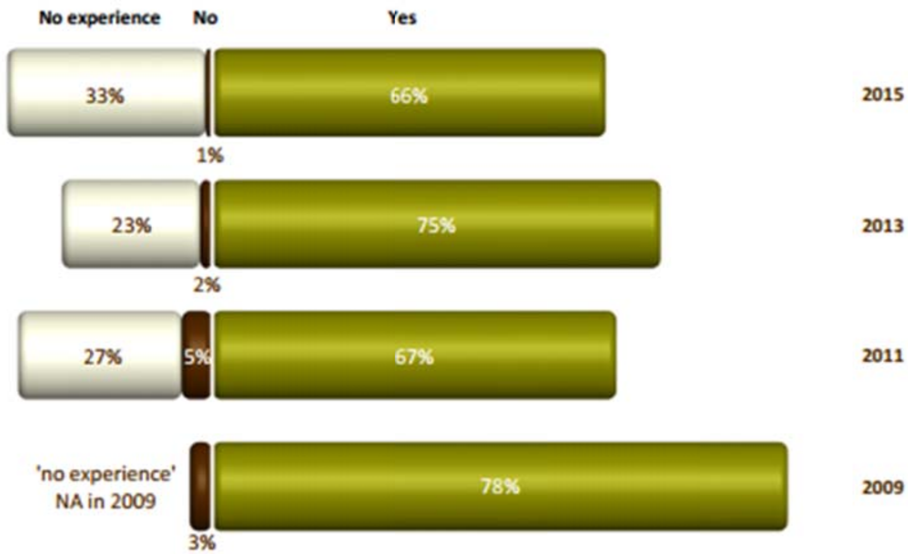
Figure 4-3: Does Remotes Take Local Environmental Protection Seriously?



Staff is Polite & Helpful

Sixty-six per cent of customers indicated that Remotes' personnel are generally polite and helpful when they come to their community to do things such as bring the electricity back on, which is nine per cent less than the previous survey and its lowest since tracking began on this question in 2009. On the contrary, just one per cent of customers said staff are not polite and helpful, which is the most favourable response achieved to date. One in three customers said they did not have any experience to answer this question.

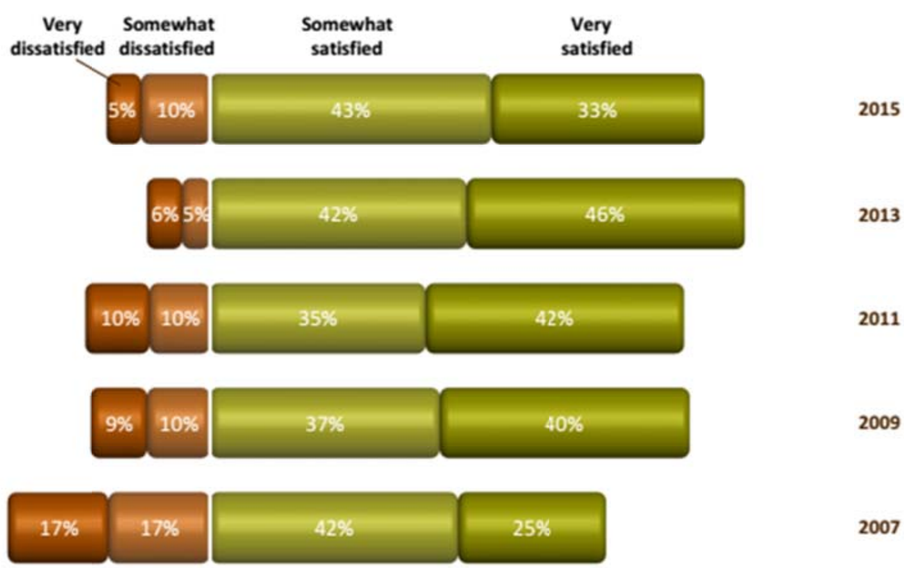
Figure 4-4: Staff Polite & Helpful



Handling of Customer Contact

When customers call Remotes' office, they can expect a person to answer the phone within 30 seconds. Figure 4-5 illustrates customer satisfaction with problem resolution. Between 2013 and 2015, customer satisfaction with how Remotes handled their contact dropped from 88% to 76%, but is still the second highest satisfaction rating since tracking began. Those who said they were very satisfied with their contact with Remotes is down 13% to 33%, its lowest level since 2007.

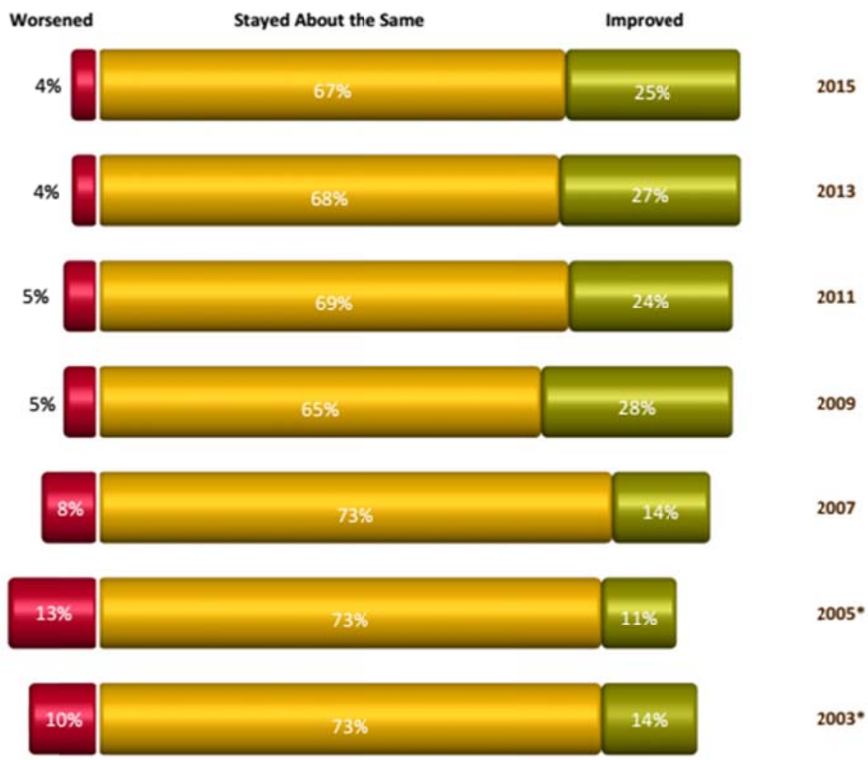
Figure 4-5: Customer Satisfaction with Problem Resolution



Perceptions of Reliability

Figure 4-6 illustrates changes in customers' impressions of their electrical service since 2003. After remaining stable below 15% from 2003 to 2007, the proportion of customers who believe the reliability of their electricity service has improved in the past few years has remained at or above 24% since. In 2015, 25% said they believe reliability has improved, while 67% of customers said it has stayed about the same. The proportion of customers who believe the reliability has worsened is approximately four per cent.

Figure 4-6: Customer Impression of Reliability

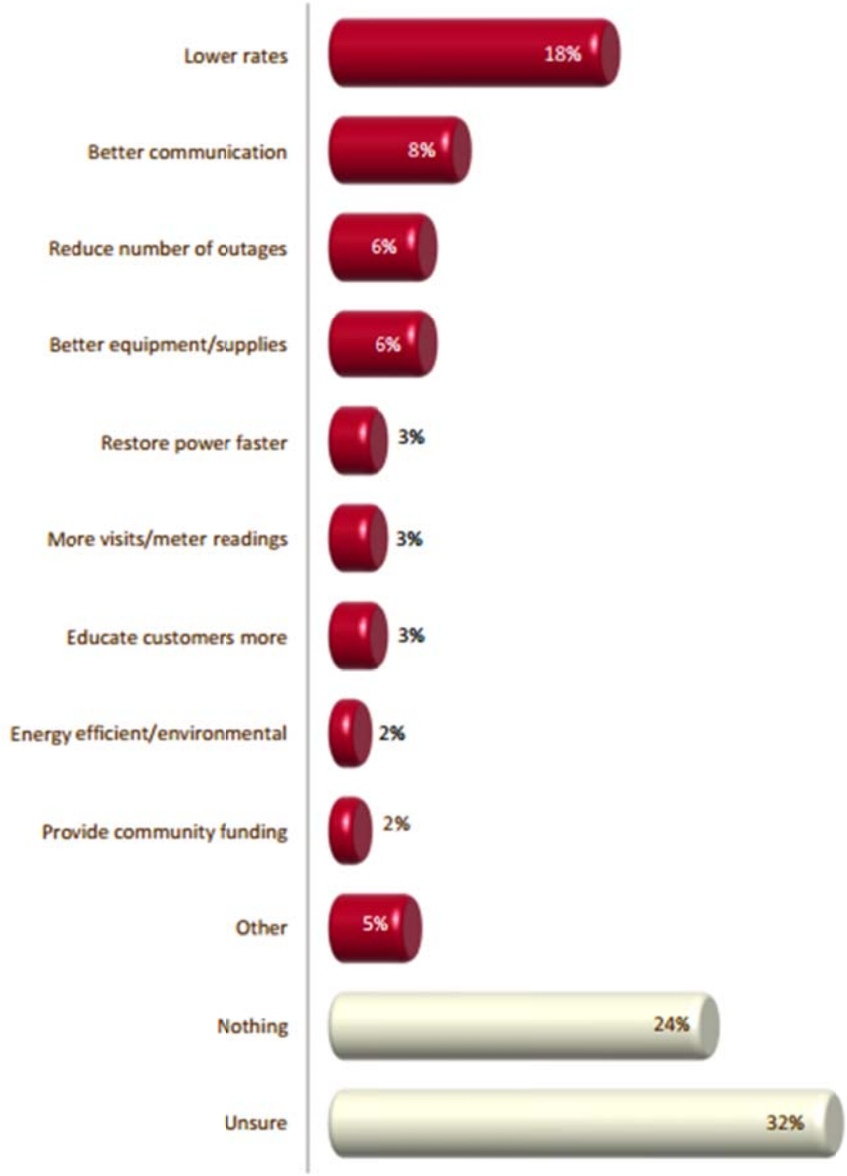


*In these years, respondents were given the option to say that reliability has worsened/improved somewhat or a lot. These responses have been combined on this chart.

Ways to Improve Service to Customers

When asked what Remotes could be doing to improve service to customers, the most frequently mentioned improvement is lowering rates (mentioned by 18% of customers). The desire for better communications was mentioned by eight per cent of respondents, while reducing the number of outages and using better equipment and supplies were each mentioned by six per cent of respondents. When respondents offered an answer that could not be classified on the list of response categories provided to interviewers, their answers were recorded verbatim by the interviewer. Figure 4-7 summarizes the response to this question.

Figure 4-7: Ways to Improve Service Identified by Customers



4.2.5 REG Investment Prioritization (5.4.2e)

Remotes' customers have indicated that REG is important to them; therefore, the accommodation of REG is given high priority in terms of resources made available by Remotes. However, plans to install new REG in three communities are funded by the communities themselves through INAC and are compared to other investments by Remotes as part of the rate base. Remotes will pay the communities for the power produced based on the diesel fuel cost avoided.

4.3 System Capability Assessment for REG (5.4.3)

4.3.1 Forecast REG Connections (5.4.3a / 5.4.3b)

Remotes' service areas are not included in the FIT program offered by the IESO. However, Remotes provides its customers with the option to install REG and sell energy to the grid based on the avoided diesel fuel cost.

A biomass project is being developed in Whitesand under Remotes' REINDEER program. If the project develops as planned, it is anticipated that electrical output could displace electrical load within the community and that settlement would be based on the avoided cost of diesel fuel in that community. No project timeline has yet been developed for the construction of this project.

Another project, supported by federal and provincial grants, is currently being developed by Fort Severn First Nation and private sector developers. Remotes' role in this project is to ensure the ongoing reliability and stability of the existing microgrid and to ensure that the project can be integrated into the existing generation system. The project is staged, with 40 kW of net-metered solar installed to date. When fully installed, the project will qualify for Remotes' REINDEER program and, consistent with that program, Remotes will pay for the electricity produced based on the avoided cost of diesel fuel.

A solar/battery microgrid project, supported by provincial grants, is also planned for Gull Bay. The project is currently in the very early stages. It is anticipated that the project will also qualify for Remotes' REINDEER program and that settlement will also be based on the avoided cost of diesel fuel in that community.

Fifteen small customer-owned solar net metering projects are now in service.

4.3.2 REG Connection Capacity and Constraints (5.4.3c / 5.4.3d)

There are no constraints on Remotes' distribution system that would prevent the connection of REG. The sizes of REG projects are limited by the load in the communities and the integration with existing generation.

4.3.3 Embedded Distributor Constraints (5.4.3e)

Remotes does not have an embedded distributor.

4.4 Capital Expenditure Summary (5.4.4)

Table 4-14 presents the historical and forecast capital expenditures and system O&M. Since this is Remotes' first DSP filing, historical years do not include plan and variance numbers for each investment category.

Table 4-14: Historical and Forecast Capital Expenditure and System O&M

Category	Historical															Forecast				
	2013			2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Act*	Var	Plan				
	$'000		%	$'000		%	$'000		%	$'000		%	$'000		%	$'000				
System Access		123			31			42			70			0		0	0	0	0	0
System Renewal – Distribution		756			504			544			760			501		522	609	643	654	670
System Renewal – Generation		3,401			3,615			1,288			2,434			1,728		1,644	2,636	3,369	3,791	2,221
System Service – Distribution		0			0			0			0			0		0	0	0	0	0
System Service – Generation		456			(193)			(19)			0			413		505	726	675	391	848
General Plant		691			677			473			914			1,085		565	572	581	590	598
Net Capital Expenses	**7,747**	**5,427**	**-30%**	**6,834**	**4,634**	**-32%**	**6,058**	**2,328**	**-62%**	**5,060**	**4,178**	**-17%**	**3,727**	**3,727**	**-**	**3,236**	**4,543**	**5,268**	**5,426**	**4,337**
System O&M	18,662	18,335	-2%	18,092	18,601	2%	20,644	16,492	-20%	21,463	18,060	-16%	20,760	20,760	-	21,291	22,260	23,650	24,095	24,281
Total Spend	**26,409**	**23,762**	**-10%**	**24,926**	**23,235**	**-7%**	**26,702**	**18,820**	**-30%**	**26,523**	**22,238**	**-16%**	**24,487**	**24,487**	**-**	**24,527**	**26,803**	**28,918**	**29,521**	**28,618**

**0 months of actual data included in 2017.*

4.4.1 Variances in Net Capital Expenditures

The variances in the system access category cannot be calculated as a percentage since there is no planned spending each year based on 100% contributed capital. Therefore, variances in this category are due to not all the cost being recovered from customers.

The annual Remotes' capital and operation and maintenance work programs are subject to many different contributing factors beyond Remotes' control. This can result in large variances in the annual expenditures. Some of these factors include:

Uncertainty of INAC funding

Funding for growth-related capital is mainly a federal responsibility. INAC faces funding constraints and both the timing for funding approvals and amounts of funding available are uncertain and require planning flexibility. INAC funding approvals may be determined in-year, after Remotes' business plan is approved. INAC design, approval and funding cycles are also lengthy and complex in nature. In response to customer needs to connect to the electrical system, Remotes adjusts its planned work program to accommodate upgrade projects.

Remote Community Accessibility

Most of Remotes' communities are accessible only by air or winter roads. Due to the cost of air transportation, and to the size and weight of some of the equipment and materials required to perform work programs, winter roads are relied upon for transportation. If the appropriate weather conditions are not met in order to construct winter roads, it is not feasible to get the equipment and materials to site and therefore the work must be deferred.

Failures

Remotes maintains its fleet of generators as guided by the original manufacturer. Sometimes a unit may fail unexpectedly. Responses to failures are initially treated as maintenance. In order to maintain the supply of power to customers in remote communities and to be prepared for the next system contingency in the community, all failures are treated as an emergency. Because of the minimal generation redundancy, the failure of a subsequent unit may lead to a community going dark. Without running generators, the community has no power, lights, or water. This situation can lead to an evacuation of the community and damage to critical community infrastructure.

Customer

Whether generation or distribution in nature, Remotes strives to meet customer and community needs and commitments made to customers. Housing connections, often delay betterments as crews are moved to more impactive customer work. Generation upgrades are critical to community development and well-being, so other generation projects are deferred.

4.4.1.1 2013 Net Capital Variances

2013 net capital expenditures were 30% below plan due to the following:

- Delayed Start for two generator unit replacements in Lansdowne due to the failure of the Deer Lake B unit;
- Re-prioritization of civil staff house improvement projects to instead focus on garage improvements in three communities;
- Deferral of protection upgrades and switchgear work due to increased engineering involvement in the planned replacements in Sandy Lake and Sachigo Lake;
- Redeployment of technical and management staff to the CIS project; and
- The nature of the work required to certify fire systems was determined to be maintenance in nature once the program started.

The variance was partially offset by:

- Unplanned costs for replacement of the Deer Lake B unit; and
- Increased engine overhauls (two additional units).

4.4.1.2 2014 Net Capital Variances

Capital expenditures in 2014 were 32% below plan due to the following:

- A decision to cancel planned replacements of the Wapekeka C unit and the Fort Severn C unit due to an in-year agreement with INAC to fully fund an upgrade of both units;
- Bearskin B unit deferred due to lower than forecast operating hours;
- Marten Falls unit operating and reliability deficiencies were corrected, therefore the unit was not replaced;
- Lower than planned garage construction costs in two communities; and
- A decision to defer to 2015 some of the work associated with refurbishing the Sultan run-of-the-river hydroelectric plant after a catastrophic failure, as the work was more technically complex than originally expected.

The variance was partially offset by:

- Day-tank replacement work required to meet fuel code requirements; and
- Leaking roof of the Deer Lake staff house that necessitated capital repair and the completion of other civil work while staff were at site.

4.4.1.3 2015 Net Capital Variances

Capital expenditures were 62% below plan due to the following:

- A decision to focus on fully recoverable INAC upgrade projects that would allow customers in three communities to connect to the electrical system. This resulted in the removal of connection restrictions for all three communities;
- Engine replacements were lower as they were completed within the scope of these upgrade projects; and
- Day tank improvements, the Wapekeka 600-V upgrade and capital betterments work were also deferred due to this shift in priorities.

The variance was partially offset by:

- Above-plan spending on the Lansdowne A unit engine replacement; and
- The completion of rebuild work at the Sultan run-of-the-river hydroelectric facility.

4.4.1.4 2016 Net Capital Variances

Capital spending was 17% below budget due to the following:

- A decision to reprioritize work to focus on INAC-funded generation upgrades that would allow customers in two communities to connect to the electrical system;
- An engine replacement project was returned to inventory, showing a timing difference on annual capital spending;
- The deferral of the planned replacement of a generator in Hillsport and a generation sustainment project in Marten Falls to focus on INAC-funded upgrade work;
- Lower than planned cost to replace the Bearskin B unit; and
- The Shoulderblade hydroelectric generator rebuild cost less than estimated as the required work was not as significant as expected.

The variance was partially offset by:

- The unplanned replacement of Deer Lake unit B.

4.4.2 Trends in Capital Expenditures

The average annual spending in the system access category over the historical period[1] was $53k. System access programs are fully recoverable and are budgeted so. However, occasionally a new-connect is only 50% recoverable from the customer. As this is very rare, it is not budgeted for. The resulting average actual costs come from these partially unrecoverable new connects and also from the net costs of fixed price billings, where the work could not be fully bundled with other work in the community. The forecast spending is $0 each year since programs in this investment category are fully-recoverable.

The average annual spending on distribution system renewal over the historical period[1] was $613k, while the average annual forecast spending is $619k. Although the number of distribution assets under management by Remotes is expected to increase over the forecast period when the new communities are added to the service area, no major increase in distribution system renewal spending has been planned since INAC is funding upgrades to the distribution lines before they are transferred to Remotes. Increased metering costs have been budgeted based on the anticipated service area additions.

The average annual spending on generation system renewal over the historical period[1] was $2.493M, while the average annual forecast spending is $2.732M. Over the historical period, some investments in this category were either deferred or transitioned to a fully-recoverable generator upgrade project. Planned investments over the forecast period to replace generators, overhaul generators, and civil repair work at diesel generating stations are based on the conditions of the respective assets.

[1] 2017 spending based on budgeted amount only.

There were no expenditures in the distribution system service category over the historical period and none have been budgeted over the forecast period.

The average annual spending on generation system service over the historical period[1] was $131k, while the average annual forecast spending is $629k. Gross spending in this category is dominated by generator upgrades, but these costs are fully recoverable. The non-recoverable portion of these costs is mostly attributed to SCADA, PLC, and fuel tank control upgrades. In 2013, Remotes attempted to contract resources to complete the SCADA and PLC project, as specialized information technology, networking, and programming skills are required to complete this project. SCADA and PLC investments were made, but were subsequently expensed in 2014 when the capital portion of the project did not materialize. During 2014 and 2015, Remotes attempted to hire contract staff to perform the work but were unsuccessful due to the unusual nature of Remotes' business and the specific needs required for the system. It was then determined that this type of work required a full-time dedicated professional, with specialized expertise, and the position was filled in 2015. Additional SCADA and PLC upgrades have been budgeted for 2017 and each year of the forecast period. Fuel system improvements were made in Lansdowne in 2013 for $140k and a larger scope of work is planned in 2022 to upgrade the bulk tank platforms and controls in Sandy Lake and Biscotasing (estimated to be $495k).

The average annual spending on general plant over the historical period[1] was $768k, while the average annual forecast spending is just $581k. Facilities improvements in Lansdowne, Kasabonika, and Deer Lake over the historical period were more extensive than those budgeted over the forecast period. Investments into garages, water wells, and the Beaverhall maintenance shop over the historical period were likewise more extensive than the planned improvements over the forecast period.

4.5 Justifying Capital Expenditures (5.4.5)

4.5.1 Overall Plan (5.4.5.1)

4.5.1.1 Comparative Expenditures by Category over the Historical Period

Comparative capital expenditures by investment category over the historical period are presented in Table 4-15.

Table 4-15: Historical Net Capital Expenditures by Category

Investment Category	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Budget
System Access	122,909	30,765	42,407	69,913	0
System Renewal – Distribution	755,858	504,031	543,694	759,715	501,360
System Renewal – Generation	3,401,157	3,615,497	1,287,531	2,434,356	1,728,000
System Service – Distribution	0	0	0	0	0
System Service – Generation	456,184	(193,493)	(18,768)	0	413,000
General Plant	690,724	677,492	472,718	914,193	1,085,000
Total	**5,426,832**	**4,634,292**	**2,327,582**	**4,178,177**	**3,727,360**

4.5.1.2 Forecast Impact of System Investment on System O&M Costs

Table 4-16 lists summarizes the forecast system O&M spending into four categories: distribution, generation, common (i.e. northern strategies and community relations), and environment (e.g. waste management, spill management and monitoring, incident follow-up, environmental management system implementation).

Table 4-16: Forecast System O&M Expenditures

Investment Category	2018 Budget	2019 Budget	2020 Budget	2021 Budget	2022 Budget
Distribution O&M	4,393,000	5,055,000	5,567,000	5,671,000	5,496,000
Generation O&M	15,496,000	15,786,000	16,737,000	17,024,000	17,315,000
Common O&M	339,000	336,000	241,000	273,000	320,000
Environment O&M	1,063,000	1,083,000	1,105,000	1,127,000	1,150,000
Total	**21,291,000**	**22,260,000**	**23,650,000**	**24,095,000**	**24,281,000**

Remotes investigated the relationship between capital spending and system O&M costs. Regardless of the capital spending, generator maintenance is required every 2,500 engine-hours. Due to the associated flight and fuel costs of this maintenance, there is no reduction to system O&M costs from capital investment.

4.5.1.3 Investment Drivers by Category

The investment drivers by category are presented in Table 4-17.

Table 4-17: Investment Drivers by Category

Investment Category	Drivers	Projects / Activities
System access	Customer service requests	New customer connections and service upgrades Fixed price layouts Service cancellations
System renewal	Assets failure	Damage claims Defective meter replacements
	Assets at the end of their service life due to failure risk	Small external demand requests Distribution system improvements Generator replacements Generator overhauls Diesel plant civil improvements Day and bulk fuel tank replacements
System service	System capacity	Generator upgrades
	System reliability and operational efficiency	SCADA and PLC upgrades
General plant	Non-system physical plant	Housing improvements Storage buildings and miscellaneous civil projects Minor fixed assets

4.5.1.4 REG Requirements

As per the REG capacity assessment in Section 4.3, there are no constraints on Remotes' system that would prevent the connection of REG. The sizes of REG projects are limited by the load in the communities.

4.5.2 Material Investments (5.4.5.2)

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. For this Application, the threshold is $283,000. Appendix A presents the project narratives for the material investments in the 2018 Test Year.

Appendix A: Business Cases for Material Investments

Material Investments in the 2018 Test Year

Table of Contents

New Customer Connections & Service Upgrades

1. Project/Program Description

1.1.Current Issue

Capital projects included under this program are customer-initiated requests for connection to Remotes' distribution system and/or expansion of connection capacity to accommodate such requests. With population changes and more intensive use of electricity in remote communities, the overall number of new load connections for Remotes has increased in recent years and is expected to continue growing.

1.2. Project Scope

New customer connections vary from year to year and may include provision/expansion of distribution lines, transformers, switches, fuses, meters, and electrical termination facilities.

1.3. Main and Secondary Drivers

This program is driven by customer service requests, as per Table 1-1 in Remotes' DSP.

1.4. Performance Targets and Objectives

Responding to customer requests is a key factor in maintaining customer satisfaction. Remotes tracks customer satisfaction levels by way of a third-party survey issued every second year, reporting the results as a part of its scorecard.

2. Project/Program Justification

2.1. Information Used to Justify the Investment

Investments in this program are initiated by customers and 100% recoverable, as specified in Remotes' asset management process.

2.2. Alternatives Evaluation

Alternative 1: Do nothing

Access to electricity is a key quality of life indicator, so the "do nothing" option is therefore not feasible.

a) <u>Project Design/Implementation Options</u>

New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*, made under the *Electricity Act, 1998*.

2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017*	2018	2019	2020	2021	2022
Capital (Gross)	477	437	559	342	629	658	768	809	824	840
Contributions	(354)	(432)	(537)	(317)	(629)	(658)	(768)	(809)	(824)	(840)
Removals	(13)	(1)	(18)	(3)	-	-	-	-	-	-
Net Capital	**110**	**5**	**5**	**22**	**-**	**-**	**-**	**-**	**-**	**-**
O&M	-	-	-	-	-	-	-	-	-	-

*0 months of actual spending included in 2017

b) Start Date
January 1, 2018

c) In-Service Date
December 31, 2018

d) 2018 Test Year Expenditure Timing

	Forecast Cost ($ '000)			
	Q1	Q2	Q3	Q4
Capital (Gross)	164.5	164.5	164.5	164.5
O&M	-	-	-	-

e) Comparative Expenditure Information

The work varies year-to-year based on the size, nature, and volume of construction activities in the communities.

2.4. Project Benefits

a) Operation Efficiency and Cost Effectiveness

New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*. In doing so, Remotes manages the engineering and design costs of these projects, while providing consistent design quality throughout its service territory. Since these programs are customer-funded, the resulting cost savings are passed directly on to customers.

b) Customer

The net benefit to customers is connection to the electrical system.

c) Safety

All new construction conforms to the latest standards for health and safety protections and performance.

d) Cyber-Security, Privacy

New smart meters installed under this program as part of the customer connection or service upgrade meet the latest cyber-security standards.

e) Co-ordination and Interoperability

As for all customer-initiated projects, Remotes works closely with the First Nation community when planning and funding the projects.

f) Economic Development

Connecting new customers to the system encourages economic growth in the community.

g) Environment

The investment will not have any negative environmental effects. Where the scope of a project includes the replacement of distribution transformer(s), newly-procured transformer units meet the latest standards in energy efficiency.

h) Final Economic Evaluation

N/A

i) System Impacts

The connection of new customers to the system impacts the system capacity relative to Remotes' planning criteria and, therefore, impacts the ability to connect additional customers in the future. Remotes accounts for this impact during its planning and works closely with the communities it serves to ensure adequate system capacity is in place to serve their immediate and future needs.

3. Prioritization

This is a non-discretionary program since it is driven by customer service requests and the costs are fully recoverable.

4. Execution Path

4.1. Implementation Plan

Projects within the program are requested by customers. Customers follow a standardized connection process by calling Remotes customer service department. At a high level, the process includes requesting service, designing the layout, and setting up an account. Once the Electrical Safety Authority (ESA) has inspected the premises, connection and construction work takes place after payment is received.

4.2. Risks and Risk Mitigation

Connections are priced two ways: variable or fixed. The costs of variable connections 100% recovered and billed as incurred. To maintain affordability of fixed-price connections, travel costs are assumed to be zero and must be coordinated with other work in the community. Every effort is made to fully recover the costs of fixed-price connections; however, when coordination with other work is not possible, fixed-price connections can be under-priced based on the need to meet customer/OEB timelines.

4.3. Timing Factors

Year-over-year fluctuations in the volume of work performed under this program vary based on the number of customer requests received each year. The timing of work depends on when the customer request is made.

4.4. Cost Factors

The number of customer connections and service upgrades required each year are forecast based on historical trends. The volume of work fluctuates each year depending on the number of requests made by customers. In 2018, it is in anticipated that Cat Lake will be added to Remotes' service area, which has been accounted for in the plan.

Controllable costs are minimized by using standardized designs. Since projects under this program are completely recoverable, the cost savings are passed on to customers.

4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% of customers stated that having electricity when they need it is a key driver to their satisfaction. New customer connections and service upgrades allow customers to connect to Remotes' distribution system in their community and have vital access to electricity. Projects under this program are initiated by Remotes' customers.

4.6.Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Distribution System Improvements

1. Project/Program Description

1.1. Current Issue

Decisions to proactively replace distribution system assets are based on inspection and asset condition assessment work performed in 2016. Poles which are hollow, exhibit severe surface rot, woodpecker damage, or otherwise identified to be unsafe, or in poor or very poor condition, require replacement. Leaning poles are realigned and substandard conductors are replaced where deficiencies are identified. Other distribution system defects related to transformers and other equipment are identified during field inspections can also necessitate capital replacement due to failure risk, safety concerns, or as otherwise applicable.

Most of Remotes' existing distribution assets were installed in the 1980s. To ensure a long-term sustainable approach to management of the distribution assets and to smooth out the potential revenue impacts of replacing all the assets in a very short window, Remotes performs betterments based on the age of the assets. Improvements to distribution systems in 2018 also include the installation of Viper switches which enable operators to sectionalize load to improve cold load pickup and to reduce the duration of community-wide distribution outages, by allowing immediate on-site outage response.

1.2. Project Scope

This program includes work on all distribution assets – primarily poles, but also conductors, distribution transformers, air break switches, reclosers, and step-up transformers. Major betterments are performed in one or two communities each year and minor betterments to address defects are performed in other communities.

The project scope in 2018 includes major betterments in Sultan and Bearskin Lake. The asset condition assessment identified 17 poles requiring replacement in Bearskin Lake and 32 poles requiring replacement in Sultan. Both major betterments include additional pole replacements to mitigate clearance hazards and substandard designs. In Sultan, the planned betterment work also includes replacing old poles in the community that were not necessarily identified as defective, but require replacement to mitigate uplift and design issues that are created by the replacement of surrounding poles. System bus upgrades may also be required because of the pole replacements. Due to work and planning efficiency and mobilization costs in remote communities, it is always preferred to bundle work.

Starting in 2013, Remotes began installing Viper switches in communities to improve cold load pick up and to enable the operator to respond to community-wide outages caused by problems on the distribution system that the operators are not qualified to respond to. Improvements planned for 2018 include Viper switches to be installed in Lansdowne and Fort Severn. These upgrades are expected to provide the local operator the flexibility to sectionalize load to improve reliability and improve the cold load pickup capability. Remotes plans to install at least one Viper switch in every mid- to large-sized community and is installing Viper switches in two communities per year as part of a multi-year plan.

1.3. Main and Secondary Drivers

The main driver for this investment in the system renewal category, as per Table 1-1 in Remotes' DSP, is assets at the end of their service life due to failure risk. The secondary drivers are improved reliability, safety, and cold load pickup on the distribution systems.

1.4. Performance Targets and Objectives

Improvements to the distribution systems are critical to maintain system reliability. Proactive replacement of assets under this program improves Remotes' customer-oriented performance and reduces the frequency of outage occurrences (the SAIFI metric). This investment targets outages due to defective equipment, foreign interference, and adverse weather. New Viper switches included in this program improve system reliability by reducing the duration of outages (the SAIDI metric). Reliability is one of the key drivers to customer satisfaction to Remotes' customers. This program also reduces distribution losses through replacement of substandard conductors and distribution transformers.

Improvements to distribution system assets are a key component of Remotes' asset lifecycle optimization policies and practices. Replacements and refurbishments of distribution assets include planned improvements and component replacement required to maintain the operation of distribution lines and associated equipment. Overhead line sections, wood poles, Viper switches, and distribution transformers are the highest priority assets under this program.

Improvements planned for 2018 include Viper switches to be installed in Lansdowne and Fort Severn. In Fort Severn, the fifteen-minute high cold load pickup was 746 kW in 2016, which exceeds the peak load in this community (i.e. 650 kW in 2015) by 15%. In Lansdowne, the cold load pickup was 647 kW in 2015, which exceeds the peak load in this community by 12%. New Viper switches in both locations will improve the cold load pickup and on-site trouble response options in these communities.

1.5. Condition of Assets

A detailed inspection on Remotes' poles was done in 2016 and their condition divided into three categories:

- Very Poor - emergency replacement,
- Poor - replace within five years,
- Good - no replacement within five years.

No poles were in very poor condition, but 115 poles were found to be due for replacement in the next five years. The replacements will be divided over the five-year period.

The poles assessed to be in poor condition in the communities of Bearskin Lake and Sultan are targeted in 2018.

Condition	Very Poor	Poor	Good
Community	**Number of Poles**		
Bearskin Lake	0	17	284
Sultan	0	32	90

1.6. Customer Impact

a) Customer profile for each community:

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	Street Lightning	Std A – Res. – Air	Std A – GS – Air	Total
Community	**Number of Customers**							
Bearskin Lake	123	-	11	4	-	9	27	**174**
Fort Severn	86	-	19	-	1	10	28	**144**
Lansdowne	72	-	5	2	1	8	16	**104**
Sultan	35	23	9	-	-	-	-	**67**

b) Customer impacts for each community:

The value of customer impact is defined as follows:

- High – less than ten per cent seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Bearskin Lake	174	640	High
Fort Severn	144	650	High
Lansdowne	104	577	High
Sultan	67	186	Medium (34% seasonal)

A planned replacement of 17 poles in Bearskin Lake would likely require three two- to four-hour planned outages affecting 58 customers at a time. An unplanned outage in Bearskin involving a single pole failure would take eight hours to rectify (mobilize crew and flight, flight time, mobilization of pole and replacement on site). With 17 poles nearing end-of-life, such an outage may occur once or twice without the planned project. A similar one-pole failure in Sultan would require nine hours to rectify the outage, due to the longer flight time.

For Viper switches, the operator can respond to a community-wide distribution outage without having to dispatch a crew or can restore the service. The Viper switch is expected to reduce the duration of community-wide outages as well as lessen the adverse operating impacts on costly generation assets.

2. Project/Program Justification

2.1. Information Used to Justify the Investment

The investment is justified based on inspection results on the distribution system. The communities targeted for major betterments were last inspected in 2016 and the results indicate the need for proactive replacements.

2.2. Alternatives Evaluation

Alternative 1: Do nothing

In the case of the "do nothing" scenario, the assets are not replaced proactively and are instead run to failure.

Alternative 2: Major betterment in another community

One or two communities are selected for a major betterment each year; this alternative considers major betterments that could be done in other communities.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, the distribution assets are run to failure. System reliability and customer satisfaction would suffer due to an increased occurrence of outages. Given the remoteness of the company's service territory, proactive replacements are more cost effective than reactive replacements, as a variety of factors beyond the utility's control could interfere with its ability to conduct the work on a reactive basis. As such, run-to-failure is not an optimal approach in accordance with Remotes' asset lifecycle optimization policies and practices. Planned work results in shorter planned outages times compared to unplanned replacement and allows Remotes to notify its customers before work is done. Pole failures are highly impactful to customers and planned work. Trouble call responses in the remote communities are disproportionately costly to mobilize and very disruptive. In case of an unplanned outage, crews are often pulled from planned jobs and the customers are out of power until the crews can be mobilized and reach the locations.

The 2016 asset condition assessment determined that Sultan has the most poles in need of replacement. While this is a small community with less than 100 customers, 26% of the poles are in need of replacement. Eighty-nine per cent of the poles in this community were installed in 1980 or earlier. Most of the poles are cedar with limited initial treatment, which are attractive homes for birds and insects. Most of these poles were installed to a 40-foot standard and modernizing the distribution system to 45 feet will improve clearances and facilitate additional joint-use applications. Other factors affecting the prioritization of this community include:

- There is an opportunity to also relocate transformers to areas more accessible by vehicles, which will reduce future trouble call costs.
- The working efficiency is major factor for this project since Remotes does not have equipment on site. All vehicles (e.g. trucks, RBDs, backhoes) will need to be brought in, so it is much better to mobilize once.

Bearskin Lake has the second most poles in need of replacement, with 17 assessed to be in poor condition. As shown in Section 1.6(b), the value of customer impacts in this community is high since there are no seasonal customers. There are 174 customers served and 640 kW of peak load at risk.

Major betterments in this community include additional pole replacements to mitigate clearance hazards and substandard designs. Therefore, this community was selected for a major betterment.

b) Comparison of Project Timing Alternatives

Projects in this program are community-focused: increasing the rate of asset replacement in the community would overharvest the assets that can be expected to remain operable in the medium term, while decreasing the rate of asset replacement would not mitigate the failure risk to the system presented by the identified deficiencies of targeted assets. Remotes' asset lifecycle optimization policies and practices state that poles should be replaced before they fail, pose a safety hazard, or cause a service interruption. Where possible, these replacements are made when other planned work in the community is planned to increase efficiency (fewer trips to the community and lower mobilization costs in the community) and minimize the number of planned outages.

c) Analysis of Project Enhancements

The program includes "like-for-like" renewals of distribution assets, whereby an asset identified as a failure risk is replaced with a new asset that conforms to modern distribution system standards. As an enhancement to this program, new Viper switches are installed to improve the reliability and cold load pickup of the distribution systems. Without these new switches, it is expected that the duration of outages experienced by customers would increase. Some "like-for-like" asset renewals include improvement to the most up-to-date standards and practices.

Locations for Viper switches are determined based on the peak load, cold load pick-up needs, and analysis of existing assets in service. In Fort Severn, the fifteen-minute high cold load pickup was 746 kW in 2016, which exceeds the peak load in this community (i.e. 650 kW in 2015) by 15%. In Lansdowne, the cold load pickup was 647 kW in 2015, which exceeds the peak load in this community by 12%. New Viper switches in both locations will improve the cold load pickup and on-site trouble response options in these communities. Once the switches are installed, operators will be able to respond to abnormal situations without having to dispatch a crew. This saves the dispatch cost and delay for customers, typically four hours. Remotes plans to install two Viper switches each year until there is at least one switch in every mid- to large-sized community.

2.3. Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017***	**2018**	**2019**	**2020**	**2021**	**2022**
Capital (Gross)	1,217	543	584	817	610	636	743	783	797	813
Contributions	(271)	(138)	(72)	(59)	(134)	(140)	(164)	(172)	(176)	(176)
Removals	(250)	(64)	(54)	(67)	(73)	(76)	(89)	(94)	(96)	(98)
Net Capital	**697**	**340**	**458**	**692**	**403**	**420**	**490**	**517**	**525**	**539**
O&M	-	-	-	-	-	-	-	-	-	-

*0 months of actual spending included in 2017

b) Start Date
Mid-summer

c) In-Service Date
Late fall

d) 2018 Test Year Expenditure Timing

	Forecast Cost ($ '000)			
	Q1	**Q2**	**Q3**	**Q4**
Capital (Gross)	-	210	210	-
O&M	-	-	-	-

e) Comparative Expenditure Information

Comparative costs over the historical period are shown in the table in Section 2.3a above. The historical and future costs include travel, labour, and materials.

2.4.Project Benefits

a) Operational Efficiency and Cost Effectiveness

The proactive replacement of distribution system assets allows Remotes to efficiently allocate its resources in a planned manner. In general, proactive replacements are more cost effective than reactive replacements.

b) Customer

Customers benefit from improved reliability, which is a key driver for customer satisfaction.

c) Safety

This investment reduces safety hazards posed by defective poles and other distribution equipment identified during inspections.

d) Cyber-Security, Privacy

The new Viper switches do not include two-way communication; therefore, there is no negative effect on cyber security.

e) Co-ordination, Interoperability

Remotes coordinates with the local First Nations and Band Councils when planning betterment projects.

f) Economic Development

Most of Remotes' customers are First Nations, and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. The investment will improve the reliability of electrical service, which is conducive to economic growth in the community.

g) Environment

The proactive replacement of distribution transformers included in this investment programs reduces the risk of an oil leak or spill from the deteriorated transformers earmarked for replacement. New distribution transformers installed in the field meet the latest energy efficiency standards.

h) <u>System Impacts</u>

Investments into new Viper switches will improve the cold load pickup of the distribution systems. The investment is also expected to reduce distribution losses via the conductor and distribution transformer replacements.

3. Prioritization

3.1. Criteria for Prioritization

This program is measured against the following four (4) risk categories:

1. Customer/reliability
2. Regulatory relationship
3. Financial
4. Reputation

a) <u>Customer/reliability</u>

Historical reliability is not tracked on an individual community level. An unexpected and sustained outage in Bearskin Lake would require approximately four hours to arrange a crew and respond on-site. Sultan would take approximately eight to ten hours to dispatch and resolve the issue. Without executing the proposed project, it is expected that the occurrence of outages would increase.

The expected magnitude of reliability improvements in Fort Severn and Lansdowne due to the installation of new Viper switches cannot be readily quantified; however, the installation of this equipment would allow immediate on-site operator response to restore power. The switches facilitate partial loading in case of a generator outage.

b) <u>Regulatory</u>

Without the project as planned, safety and reliability may be compromised, which would constrain Remotes' regulatory relationship.

c) <u>Financial</u>

Absent the project as planned, regular ongoing maintenance would be required on the lines and equipment, which would increase system O&M costs. Emergency repairs are not as efficient as planned maintenance. Trouble costs generally start at $10k due to transportation, while an emergency pole replacement could cost as much as $30k. Bundling the work into a planned project reduces mobilization costs in terms of transportation to the community and within the community itself. Once a crew is in the community, they must excavate a hole (if required to set the pole), load the pole on a pole-trailer, transport it to the location, erect the pole, attach wires and conductors, and frame it with the crossarm and insulators. It takes longer to load and transport a single pole several times than to load several poles at once.

The new Viper switch installations are designed to allow immediate on-site operator response, which reduces travel and trouble call costs.

d) Reputation

Customers deserve and desire power that is good, safe, and reliable.

3.2. Consequences of Deferral

Deferring the Distribution System Improvement program would increase the probability that the assets would fail during the year, negatively impacting system reliability. Reactive replacements are more expensive than proactive replacements. Deferred renewal of the distribution system would increase the investment needs in future years and would cause spikes in revenue requirement compare to balance year-over-year investments.

3.3.Priority

Customer-initiated work is Remotes' first priority. Capital and maintenance investments into assets (e.g. this program) are prioritized next.

4. Execution Path

4.1. Implementation Plan

The planned work will be completed by a dedicated lines crew experienced in this type of work. Major betterments in the communities are planned to reduce the amount of resources spent on travel. In the case of minor betterments, the crews typically spend a week in the community to perform the necessary capital and O&M work. Implementation depends on the final scope of work and resourcing. Planning and material lead times both affect the order of project implementation. Sultan is slightly preferred based on asset condition and lower past investment.

4.2.Risks and Risk Mitigation

Cost is the largest risk to Remotes' capital projects and programs, since it is costly to transport equipment and crews to the communities. Remotes mitigates this risk through prudent project planning and work execution according to standard operating procedures. Large tools and equipment are stored in each community to reduce costs and mitigate the availability risk.

While the timing and priority of assets to be replaced may change during the year, Distribution System Improvements are well understood and generally meet cost and timing objectives.

4.3.Timing Factors

Crews are stationed in Thunder Bay and Remotes keeps lodgings for its crews in each community it serves. There is just one lodging facility per community; therefore, only one crew may be working in a community at a time without resorting to renting additional lodging space. The risk to limited accommodation is mitigated through coordination between crews. If emergency work is required in a community, then the timing of the planned capital investment work may be adjusted.

The ability to safely fly in crews also affects the timing of the project. If for any reason the community is inaccessible, the timing of the project must be adjusted accordingly.

The intensity of asset investment is not expected to fluctuate significantly over the forecast period. In the case that additional emergency capital work on the distribution system is identified during the year, the project plan may be altered to reflect the new priority of the assets to be replaced.

4.4.Cost Factors

The final cost of the project is largely affected by transportation costs, but is also affected by labour and material costs. Remotes has significant experience in planning and managing the expenditures associated with its distribution plant, and spending on Distribution System Improvements generally aligns with the budget.

If this program were not executed, it is expected that O&M costs would increase due to more trouble calls to repair the distribution system assets that are not being renewed.

4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% stated that a reliable source of electricity is a key driver to their satisfaction. An important part of reducing number of outages is replacing distribution assets at their end-of-life, and keeping the distribution system in good condition.

Out of the surveyed customers who indicated that Remotes could improve their service, 32% cited "lower rates" as the most important factor to improve service. In response to these comments, this program has been paced over five years to reduce its rate impact, while still mitigating the risk of asset failures on the distribution system.

4.6.Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Big Trout Lake A Generator Replacement

1. Project/Program Description

1.1. Current Issue

The A unit diesel generator in Big Trout Lake is forecast to reach 55,868 engine-hours in 2019 and is rated to be in very poor condition. The manufacturer's published recommendations for generators of this type include complete overhauls after 20,000 hours. In addition, Remotes has determined that a generator should be replaced after two rebuilds, generally at about 60,000 hours. Therefore, an engine replacement has been scheduled for this generator in 2019, with the procurement of the replacement generator to take part in 2018. Assets are often ordered and transported to site a year in advance, to mitigate transportation risks (e.g. bad weather conditions) and long lead times.

1.2. Project Scope

Unit A in Big Trout Lake is a medium-speed (1800 rpm), 600-kW unit. The generator was installed in 1996, making it the oldest medium-speed diesel generator deployed in Remotes' system. This unit was selected for replacement based on its age, the actual and forecast engine-hours, and its very poor condition.

1.3. Main and Secondary Drivers

The main driver for this investment, as per Table 1-1 in Remotes' DSP, is that the generator is at the end of its service life due to failure risk.

1.4. Performance Targets and Objectives

The proposed investment is consistent with Remotes' asset lifecycle optimization policies and practices for diesel generators. Replacement of a generator based on the maintenance history, engine-hours, reliability history, and age reduces outage risk, enhances system reliability, and improves generator efficiency.

System reliability is an important customer-oriented performance measure for Remotes. Remotes tracks its System Average Interruption Frequency Index ("**SAIFI**") and its System Average Interruption Duration Index ("**SAIDI**"), both of which are affected by the timely replacement of generators.

Improvements in fuel economy and emissions performance with new generation units would also result in improved generation efficiency and reduced greenhouse gas emission intensity, both of which are important performance measures for Remotes' customers.

One of Remotes' planning objectives is that the peak load in each community should not exceed 85% of the station rating. Before this limit is reached, an upgrade of the generating station is scheduled. The generation capacity in Big Trout Lake is 1600 kW and the corresponding connection limit is 1360 kW. In 2014 the peak load reached 1395 kW, exceeding the connection limit. A separate project planned for 2018 and 2019 to upgrade the generating station in Wapekeka and connect this community to Big Trout Lake by way of an overhead distribution line to relieve capacity constraints in both communities.

1.5. Condition of Assets

The A unit diesel engine-generator set in Big Trout Lake was installed in 1996. As of January 2, 2017, the unit has operated for a total of 48,064 engine-hours. The unit was previously overhauled twice: first in July 2005 after 20,148 engine-hours and then in June 2015 after 44,185 engine-hours.

At the time of proposed replacement in 2019, the generator is forecast to reach 55,868 hours. The unit is already in very poor condition as per asset condition assessment and should accordingly be replaced without undue delays.

1.6. Customer Impact

a) Customer profile for the community:

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	Street Lightning	Std A – Res. – Air	Std A – GS – Air	Total
Community	**Number of Customers**							
Big Trout Lake	301	-	30	6	-	10	50	**397**

b) Customer impacts for each community:

The table below presents the customer impacts for each community. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Big Trout Lake	397	1395	High

An unplanned outage in the community can be cleared in less than two hours if the operator can respond. Otherwise, the outage time varies depending on the problem. The minimum response time is four hours to dispatch a crew to Big Trout Lake. An unplanned replacement may take up to six months. Remotes maintains an up-to-date contingency analysis for its in-service generation units. If unit A fails, then the other units can continue to serve the load.

2. Project/Program Justification

2.1. Information Used to Justify the Investment

The A unit generator set in Big Trout Lake was installed in 1996 and has been operated for 48,064 engine-hours as of January 2, 2017. Its estimated engine-hours over the forecast period are shown in the table below.

Year	2017	2018	2019	2020	2021	2022
Projected Engine-Hours	50,774	53,321	55,868	58,415	60,962	63,509

This generator has been overhauled twice and, as per Remotes' asset management process, it is more economical to replace the unit rather than overhaul it a third time. The asset condition assessment determined that this unit is in very poor condition requiring immediate replacement.

2.2. Alternatives Evaluation

Alternative 1: Do nothing

The "do nothing" option considers that the generator is run to failure without intervention.

Alternative 2: Overhaul

The second alternative to a generator replacement is to overhaul the unit.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, the generator is run to failure. An unplanned outage in the community can be cleared in less than two hours if the operator can resolve the issue. Otherwise, the outage time varies depending on the nature problem. The minimum response time is four hours to dispatch a crew to Big Trout Lake. If the failure is irreparable, the outage would likely last a day; otherwise there could be rolling blackouts in the community lasting about a week. This is not the preferred option.

After two overhauls, it is no longer economical to overhaul the generator for a third time. This generator has been overhauled twice previously; therefore, replacement is the preferred option.

b) Comparison of Project Timing Alternatives

If the project was deferred by one year, the probability of increased maintenance and the risk of a catastrophic failure would increase. There is a spare 400-kW unit in the community. In the case of a catastrophic failure, the outage would likely last a day, otherwise there could be rolling blackouts in the community. In the medium term, a replacement would need to be flown in on an emergency basis.

c) Analysis of Project Enhancements

This project is a like-for-like renewal and does not include any project enhancements.

2.3. Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017*	2018	2019	2020	2021	2022
Capital (Gross)	-	-	-	-	-	767	1,423	-	-	-
Removals	-	-	-	-	-	(77)	(142)	-	-	-
Net Capital	-	-	-	-	-	**690**	**1,281**	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-

*includes 0 months of actual expenditures

b) Start Date
January 2018

c) In-Service Date
September/October 2019

d) 2018 Test Year Expenditure Timing

	Forecast Costs ($ '000)			
	Q1	**Q2**	**Q3**	**Q4**
Capital (Gross)	383.5	383.5	-	-
O&M	-	-	-	-

e) Comparative Expenditure Information

The planned total gross cost of this investment is $2,190,000 spread over two years - 2018 and 2019, with procurement of replacement generators in 2018 and installation in 2019. To compare the cost to other engine replacement investments, cost per kW should be considered. The capacity of the generator is 600 kW, so the cost per kW is $3,650.

An engine replacement was done in Deer Lake in 2016. The unit replaced is a medium speed (1800 rpm) generator with capacity 635 kW. The total cost of this project was $902,931, which equates to $1,422 per kW. Another replacement was done on the A unit in Lansdowne in 2015, a medium-speed unit rated 275 kW. The total gross cost for this project was $871,190 and the cost per kW was $3,168.

The difference between the cost of these similar investments is primarily due to the difference between the stations. The station in Deer Lake is relatively new. The station in Big Trout was built in the 1980s and is much older and smaller than the Deer Lake station. New generators use digital controls, whereas the controls in the Big Trout Lake station are analogue. The replacement will improve the voltage regulation by moving to three phases rather than a single phase. Finally, Big Trout Lake is located further from all-weather roads and further from the manufacturer.

2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

The investment supports operational efficiency since the new engine will be more fuel efficient. Auxiliary work is done alongside the replacement to reduce engine down-time, mobilization, and travel costs. The proactive replacement of a generator unit is cost effective compared to running the unit to failure, which would otherwise incur additional maintenance, outage, and emergency replacement costs.

b) Customer

The net benefit to customers is improved system reliability based on the proactive replacement of the generator.

c) Safety

The safety benefit of the proactive replacement of the generator is risk mitigation of an unplanned generator failure.

d) Cyber-Security, Privacy

The upgrade of auxiliary systems as part of the generator replacement will install fuel and control systems that comply with the latest cyber-security standards.

e) Co-ordination, Interoperability

Remotes uses standardized station designs and all new installations comply with *O. Reg. 22/04*.

Big Trout Lake has been identified to be connected to a new transmission line by an Order-in-Council issued by the Minister of Energy. The anticipated connection date is not presently known and the Regional Planning Process yielded a draft *Remote Community Connection Plan* requiring further consultation.

The planning co-ordinated with another project to connect the distribution systems of Big Trout Lake and Wapekeka and also co-ordinated with the local Band Councils.

f) Economic Development

Most of Remotes' customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. A reliable supply of electricity promotes economic growth in the region.

g) Environment

The new diesel generator set will meet the latest energy efficiency and emission performance standards, which have markedly improved since the existing unit was installed (1996). This will reduce the emissions. Furthermore, this investment ensures the reliable operation of this generator, which ensures the PLC can select the most fuel-efficient generator based on the load.

h) System Impacts

The reliable operation of Big Trout Lake Generator A will help maintain system performance.

3. Prioritization

3.1. Criteria for Prioritization

This program is measured against the following seven risk categories:

1. Customer/reliability
2. Regulatory
3. Financial
4. Efficiency
5. Environment
6. Safety
7. Reputation

a) Customer/reliability

Based on manufacturer guidelines, the probability of increased maintenance and the risk of a catastrophic failure would increase without the planned project. There is a spare 400-kW unit in the community. In the case of a catastrophic failure, the outage would likely last a day, otherwise there could be rolling blackouts in the community. In the medium term, a replacement would need to be flown in on an emergency basis.

b) Regulatory

Without the planned project, safety and reliability may be compromised, which would constrain Remotes' regulatory relationship.

c) Financial

Without the planned project, an increase in trouble with the unit is expected. The minimum response cost is $25,000. Emergency repairs are costlier since an engine may need to be procured and put in service quickly depending on the timing of its failure. Transportation costs for the unit would increase by about $100,000.

d) Efficiency

The new units are expected to be about four per cent more efficient than the older units, raising diesel fuel costs and emission levels.

e) Environment

New generators are designed to reduce emissions. The proactive replacement of the existing unit also mitigates the risk of a spill in the event of a failure.

f) Safety

Proper investment into diesel generators follow best practices recommended by manufacturers to ensure they operate safely.

g) Reputation

Customers deserve and desire power that is good, safe, and reliable.

3.2. Consequences of Deferral

Deferring this project would increase the probability that the generator fails, affecting reliability, regulatory relationship, financial risk, generator efficiency, environmental risk, safety risk, and reputation. This would affect the whole community of Big Trout Lake, approximately 400 customers.

3.3. Priority

The priority in 2018 is to purchase the engine and transport it to site to ensure that adequate generation is available to the community of Big Trout.

4. Execution Path

4.1. Implementation Plan

The 2018 costs include the design and procurement of the replacement unit. The replacement generator set is ordered in advance of winter roads. The installation, commissioning, and auxiliary upgrades will be performed in 2019. When integrating new engines into older existing systems; heating, cooling, ventilation, exhaust, electrical, fuel and control systems may be impacted. It is preferred that all necessary auxiliary work be done in conjunction with the engine replacement to reduce engine down-time, mobilization, and travel costs. The work will be done by a dedicated station crew and will be co-ordinated with another project to connect the distribution systems of Big Trout Lake and Wapekeka.

4.2. Risks and Risk Mitigation

The biggest risk to completion of the project as planned is in relation to costs and availability of transportation of the new generator to the community. This risk is mitigated through Remotes' staged implementation plan, in which the generator is procured one year earlier than the installation. However, despite the advance procurement, the unavailability of a winter road for an entire season may delay the project execution. If the risk of project delay becomes too great, then Remotes can hire a specialized aircraft to fly in the new unit, adding to the cost of the project.

Another risk to project completion is the availability of crew accommodation. Remotes has lodgings for only one crew in each community. Therefore, only one project can be implemented at a time in a community. If another project with a higher priority should suddenly come up in Big Trout Lake, it could affect the completion of this project. This can be mitigated by seeking to minimize the number of such emergencies through good planning and asset management. In the past, Remotes has also worked closely with the communities it serves to arrange for rental accommodation for its crews in case the lodgings are insufficient for the number of crews required.

Other risks to a project of this magnitude can occur due to manufacturing or installation defects. Remotes mitigates these risks by working closely with its suppliers, assigning trained personnel who are familiar with generator station commissioning, and performing commissioning testing.

4.3.Timing Factors

The project timing has been planned as per the implementation plan to allow the procurement of the generator in advance of winter roads, with the installation and commissioning planned for 2019. The timing may be affected by the availability of winter roads prior to the 2019 commissioning.

Project timing can also be affected by weather conditions affecting the ability to safely fly in crews to the community. Under this scenario, the project timing would be shifted in the year.

Remotes operates 19 generating stations serving 21 remote communities and manages 57 generators. The timing of a generator replacement may be affected by shifting priorities for generator replacements in other communities. Big Trout Lake is one of the largest communities served by Remotes (with approximately 400 customers) and Generator A was assessed to be in very poor condition – making its replacement the top priority for generator replacements over the forecast period.

4.4.Cost Factors

The cost of transportation is an important factor for replacing generators in remote communities in northern Ontario. The inaccessibility of the communities makes shipping both unreliable and expensive. Labour requirements during installation, commissioning, and testing will also affect the final cost of the project depending if any issues arise.

Without the planned project, O&M costs would increase due to enhanced maintenance requirements and the increased likelihood of trouble calls to the generator.

4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% stated that a reliable source of electricity is a key driver to their satisfaction. Replacing this generator as per manufacturer's recommendations is an important part of maintaining the reliability of the electricity system in Big Trout Lake.

4.6. Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Generator Overhauls

1. Project/Program Description

1.1. Current Issue

Diesel engines and their components are subject to deterioration that eventually leads to a decline in equipment performance and reliability, which increases environmental risk, safety risks, and incidence of failures. The engines are designed and manufactured to require capital overhauls at regular intervals to extend service life after a specified number of operating hours. This practice ensures the reliability of the engines and reduces the likelihood of a catastrophic failure. Medium-speed engines (1800 rpm) are overhauled after 20,000 engine-hours and low-speed engines (1200 rpm) are overhauled after 42,000 hours. Usually it is economical to overhaul an engine only twice over its lifecycle.

1.2. Project Scope

Four or five diesel generator engine sets are overhauled each year, depending on the size of the units. The engines are selected based on engine-hours and condition. Based on the current and forecast engine-hours, the generator units planned for overhauls will most likely be a subset of the following six:

1. Kasabonika A (1000 kW)
2. Kasabonika C (600 kW)
3. Marten Falls A (650 kW)
4. Marten Falls C (250 kW)
5. Sachigo A (635 kW)
6. Weagamow C (400 kW)

1.3. Main and Secondary Drivers

The driver for investments in the system renewal category, as per Table 1-1 in Remotes' DSP, is assets at the end of their service life due to failure risk. The generators in question have all reached the specified number of hours after which they are due for an overhaul according to the engine manufacturer's preventative maintenance procedures. They should therefore be rebuilt to ensure generation reliability and efficiency.

1.4. Performance Targets and Objectives

This investment is consistent with Remotes' asset lifecycle optimization policies and practices for diesel generators. Rebuilding generators after a specified number of hours reduces risk and ensures system reliability and generation efficiency.

System reliability is an important customer-oriented performance measure for Remotes. Remotes tracks its System Average Interruption Frequency Index ("**SAIFI**") and its System Average Interruption Duration Index ("**SAIDI**"), both of which are affected by the timely overhauls of generators. System reliability is a key driver of customer satisfaction; therefore, the investment contributes to achieving the customer satisfaction.

The implementation of this program also contributes to the achievement of the desired outcomes for generation availability through improved reliability of the generators and diesel generation efficiency through improved fuel usage.

1.5. Condition of Assets

Remotes prepared a forecast of the operating hours for each unit. The forecast will be compared to actual operating hours. The forecast is used to determine priorities for annual overhauls. Information on the other assets in service and seasonality compared to the size of the unit are also used to prioritize work to ensure the least disruption to community reliability.

1.6. Customer Impact

a) Customer profile for the community:

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	Street Lightning	Std A – Res. – Air	Std A – GS – Air	Total
Community	**Number of Customers**							
Kasabonika	206	-	14	5	-	11	17	**253**
Marten Falls	76	-	9	2	-	8	13	**108**
Sachigo Lake	131	-	14	1	1	5	13	**165**
Weagamow	244	-	24	1	1	12	26	**308**

b) Customer impacts for each community:

The table below presents the customer impacts for each community, including the expected outage duration and frequency without the planned project. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Kasabonika	264	1106	High
Marten Falls	113	494	High
Sachigo	170	718	High
Weagamow	311	1096	High

An unplanned outage in a community can be cleared in less than two hours if the operator can respond. Otherwise, the outage time varies depending on the nature of the underlying issue. The minimum response time is four hours to dispatch a crew to a community. An unplanned replacement may take up to six months. Marten Falls A is the largest generator in its community; the other three communities have larger generators that can serve the load.

2. Project/Program Justification

2.1. Information Used to Justify the Investment

Diesel engines and their components are subject to deterioration that negatively impacts equipment performance and system reliability over time. Maintenance and capital overhauls in accordance with manufacturer guidelines mitigate the risk of failure. Manufacturers recommend overhauling engines based on the number of operating hours to retain and extend the life of the unit. To proactively plan overhauls, Remotes forecasts the engine-hours based on historical trends. The units are prioritized for an overhaul based on the actual number of operating hours, the condition of the units, and their likelihood of failure. This review is performed by Remotes' generation staff who have reviewed test results and who perform regular maintenance of the units.

The projected engine-hours for the six engines shortlisted for an overhaul are shown below.

	Year	2017	2018	2019	2020	2021	2022
Generator	**Speed**	**Projected Engine-hours**					
Kasabonika A	1200 rpm	80,400	86,714	93,029	99,344	105,659	111,973
Kasabonika C	1800 rpm	19,898	21,603	23,309	25,015	26,721	28,426
Marten Falls A	1200 rpm	81,172	84,779	88,385	91,991	95,597	99,204
Marten Falls C	1800 rpm	52	75	98	121	144	167
Sachigo A	1800 rpm	15,495	19,379	23,264	27,148	31,033	34,918
Weagamow C	1800 rpm	16,767	18,615	20,462	22,309	24,156	26,004

2.2.Alternatives Evaluation

Alternative 1: Do nothing

For the "do nothing" option, regular generator maintenance is continued without any capital overhaul.

Alternative 2: Generator replacement

This alternative considers the replacement of the generator instead of the rebuild.

a) <u>Comparison of Project Alternatives</u>

In the case of the "do nothing" option, the generator is run to failure without regard for the manufacturer's recommendations. The greatest risk under this scenario is the loss of remaining life of the generator. For a medium-speed (1800 rpm) generator, an overhaul allows the generator to run for an additional 20,000 hours until its next overhaul or replacement. For a low-speed (1200 rpm) generator, an overhaul allows the generator to run for an additional 42,000 hours until its next overhaul or replacement. Without the overhaul, it is likely that the generator would require an emergency replacement before reaching its maximum number of operating hours. Replacement of the failed generator would be more expensive than the cost of an overhaul. The run to failure strategy also poses an unacceptable safety, environmental, efficiency, and reliability risk (see Section 3.1).

A planned replacement is not the optimal intervention strategy before the second overhaul is performed. None of the engines earmarked for an overhaul have been overhauled twice. The engines can be run for an additional 20,000 or 42,000 hours, at which point the need for an additional overhaul or a replacement will be assessed. The planned replacement of these engines would be about three times the cost of an overhaul and would constitute a loss of useful life. This is not the preferred alternative.

The planned project to overhaul the units is the optimal trade-off between costs and benefits and is the most economic option to extend the lives of these generators.

b) Comparison of Project Timing Alternatives

Remotes owns 57 generator units that are currently in service. If the number of overhauls is decreased each year, the overall risk of failures in at least one community would consequently increase. Based on the forecast number of operating hours, there are more generators that will require overhauls than resources to meet these guidelines. Remotes regularly monitors the generator maintenance records to determine which units are the highest priority to complete.

Remotes already checks its forecast of operating hours against its maintenance records and the results of tests on the units. If the program spending is reduced, then generation redundancy would be compromised across Remotes' service territory. Regular maintenance on the remaining generators would, therefore, also be compromised. Depending on which engines remain in service and on the season, this may necessitate rotating blackouts.

Starting a project in peak load season (midwinter) is avoided to reduce risk to other unit failures, which would run more continuous and at higher loads during this time.

c) Analysis of Project Enhancements

The scope of work does not include any project enhancements in addition to the planned overhauls.

2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017***	**2018**	**2019**	**2020**	**2021**	**2022**
Capital (Gross)	710	663	755	691	670	675	688	702	718	732
Removals	(58)	(66)	(75)	-	(67)	(68)	(69)	(70)	(72)	(73)
Net Capital	**652**	**597**	**680**	**691**	**603**	**608**	**619**	**632**	**646**	**659**
O&M	-	-	-	-	-	-	-	-	-	-

*includes 0 months of actual expenditures

b) Start Date
April 1, 2018

c) In-Service Date
November 30, 2018

d) 2018 Test Year Expenditure Timing

	Forecast Costs ($ '000)			
	Q1	**Q2**	**Q3**	**Q4**
Capital (Gross)	-	225	225	225
O&M	-	-	-	-

e) Comparative Expenditure Information

Comparative expenditures for engine overhauls over the historical period are shown in the table above. The budget is based on historical trends: the average gross spending over the historical period was $698k per year and the average gross spending over the forecast period is $703k per year. The number of generators overhauled depends on the cost – determined by the speed of the unit and its size (capacity).

2.4. Benefits

a) Operation Efficiency and Cost Effectiveness

When generators age, they become less fuel efficient. Engine overhauls renew or extend asset life, mitigating this loss of efficiency. This also prevents premature failure of the engine and defers the need for replacement. Engine replacements are substantially costlier than overhauls, so this procedure is cost-effective.

b) Customer

This investment improves system reliability for the customers in the relevant communities.

c) Safety

Proactive rebuilding of generators mitigates the risk of an unplanned generator failure, which may pose a safety concern.

d) Cyber-Security, Privacy

This investment pertains to the generators themselves and not to its controls or communication auxiliaries.

e) Co-ordination, Interoperability

Remotes coordinates with the Band Councils concerning new investments.

f) Economic Development

The majority of Remotes customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment is expected to maintain the reliability of the electrical systems and a reliable supply of electricity is good for economic growth.

g) Environment

As generators undergo operational wear-and-tear, their fuel efficiencies decrease. An engine overhaul improves the condition of the generator and mitigates the efficiency losses. Furthermore, this investment ensures the reliable operation of these generators, which ensures the PLCs can select the most fuel-efficient generators based on the load.

h) System Impacts

This investment helps maintain system performance.

3. Prioritization

3.1. Criteria for Prioritization

This program is measured against the following seven risk categories:

1. Customer/reliability
2. Regulatory relationship
3. Financial
4. Efficiency
5. Environment
6. Safety
7. Reputation

a) Customer/reliability

Based on manufacturer guidelines, the probability of increased maintenance and the risk of a catastrophic failure will increase without the planned project. Regular maintenance of the remaining generators would also be impacted, increasing the risk of community-wide outages as generators are taken out of service for maintenance. Depending on which unit failed and when a new unit could be procured and put into service, and on the season, rotating blackouts could be in place for a week or longer. Remotes does not have spare units on site in every community; therefore, the replacement unit would have to be procured and transported to the community. For the fly-in communities, this would represent an unacceptable risk to reliability as a replacement unit would need to be transported to the community. If a second unit were to fail, a community evacuation could potentially be required.

b) Regulatory

Without the planned program, safety and reliability may be compromised, which would constrain Remotes' regulatory relationship.

c) Financial

Without the planned program, additional oil changes, inspections and valve sets would still be done. Alternately, the engine may require replacement. The cost on average would be $600-$700k to replace, compared to an overhaul at approximately $200k. Any failure is treated as an emergency. Unplanned trips to the community would also be required. The remaining life of the generator would be lost and a new engine is about three (3) times more expensive than an overhaul.

d) Efficiency

Remotes' generating stations are typically designed with three generators, sized to meet load within communities. The two smaller units are normally capable of carrying the peak load in the community. This design allows for redundancy in the event of a failure. If a single generator were to fail, there would not be an outage in the community. However, there would be a loss of fuel efficiency, leading to higher volumes of fuel burnt, with higher costs and higher emissions. Depending on which generator is out of service, fuel efficiency would be affected (for example, the large unit is most efficient during peak load and is less efficient if run to meet lower loads). If Remotes' engines cannot follow load, diesel fuel consumption would increase by about 10%.

e) Environment

The reduction in generator efficiency without the engine overhaul program would increase the emissions intensity. In addition, an unplanned engine failure may create a hole in the engine block, which would leak coolant and fuel contaminants and increase the risk of fire.

f) Safety

Proper investment into diesel generators follow best practices recommended by manufacturers to ensure they operate safely. If someone is in the station when a unit fails, he or she could be struck by flying parts.

g) Reputation

Customers deserve and desire power that is good, safe, and reliable.

3.2. Consequences of Deferral

Remotes manages 57 engines. Reducing investment in engine overhauls would gradually lead to increased risk in terms of reliability, regulatory, financial, efficiency, environment, safety, and reputation.

3.3. Priority

Remotes prioritizes investments into generator overhauls based on the availability of resources. Trouble calls and operational defects always take priority over engine overhauls. This is a high priority program in the capital plan.

4. Execution Path

4.1. Implementation Plan

The work is performed between April and November to avoid a planned outage during peak load conditions in winter. The need to overhaul each unit is assessed based on the actual operating hours accrued. The timing of the overhaul is prioritized using available resources. Trouble calls and the repair of operational defects are prioritized before overhauls. Overhauls are completed by a dedicated station crew which is also responsible for the maintenance of Remotes' generators.

4.2. Risks and Risk Mitigation

Another risk to project completion is the availability of crew accommodation. Remotes only has lodgings for one crew in each community. Therefore, only one project can be implemented at a time in a community.

4.3.Timing Factors

The project plan is based on the forecast number of engine-hours for these units in 2017 and 2018, which will necessitate the overhaul. In case the actual engine-hours of the units were to differ significantly from the projection, then it may be necessary to alter the project plan in the 2018 Test Year to include generators that have reached the threshold number of engine-hours.

4.4. Cost Factors

The cost of a generator overhaul is largely based on the size of the generator. Although these costs are well understood and can be planned in accurately in advance, the units requiring an overhaul may change in accordance with the factors listed in Section 4.3 above, which may affect the final cost of the project.

Without the planned project, O&M costs would increase due to enhanced maintenance requirements and the increased likelihood of trouble calls to the generator.

4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% stated that a reliable source of electricity is a key driver to their satisfaction. Overhauling generators as per manufacturer's recommendations is an important part of maintaining the reliability of the electricity systems.

4.6.Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Diesel Plant Civil Improvements

1. Project/Program Description

1.1. Current Issue

Diesel plant civil improvements are required to maintain the safety and operability of the diesel generating stations. In the 2018 Test Year, improvements are planned at the diesel generating stations in Kingfisher Lake and Weagamow.

1.2. Project Scope

This investment includes improvements of the diesel plant in Kingfisher Lake and Weagamow. The work will include DGS siding, insulation, roofing, and concrete betterment. Diesel plant civil improvements are performed every year, and the community is chosen based on assessment of relative needs.

The diesel generator station facility located in Kingfisher Lake is a manufactured steel building. The roof structure consists of steel liner panels acting as the interior ceiling and doubling as the air/vapour barrier. The roof's thermal layer is composed of fiberglass batt insulation. The roof/ceiling support consists of horizontal steel with steel Z-girts running perpendicular to the horizontal structure to support the liner panel ceiling below. The proposed project would form a tempered air space above the existing panels. In addition, proper airflow from soffit to the ridge should also be created within the new tempered air space. By providing a tempered space above the existing steel roof, any heat loss which would occur at the eave location must now be transferred through the air space before transmitting heat to the new roof panels above. By enabling proper airflow into the air space by allowing fresh cold air in from the soffit and venting out at the ridge, heat transfer through the air space to the new steel roof panels can be significantly reduced.

Similarly, Weagamow's diesel generator station is a steel manufactured building. Roof construction consists of horizontal steel liner panel acting as the ceiling and as the air/vapour barrier for the roof. The insulation in the attic space is a single batt of fiberglass insulation. In addition to the ventilation issue identified at the Kingfisher diesel generator station, Weagamow has insufficient insulation within the attic space. As there is limited space within the existing attic for placement of additional batt insulation, the existing roof panels will be removed to facilitate additional fibreglass batt insulation and creation of a tempered air space.

1.3. Main and Secondary Drivers

The driver for investments in the system renewal category, as per Table 1-1 in Remotes' DSP, is that assets are at the end of their service life, resulting in substandard performance. In the case of civil improvements, this refers to the condition of the generating plant building itself. Poor condition of the diesel plant causes poor working conditions for Remotes' staff and can even threaten the health and safety of staff and the general public.

1.4. Performance Targets and Objectives

The proposed investment would improve daily working conditions of staff and operators in Kingfisher Lake and Weagamow, as well as mitigate safety hazards that would otherwise have to be mitigated through costly workarounds. As part of its metric tracking initiatives, Remotes tracks the number of lost time injuries and the total number of recordable injuries and upgrades to the diesel plants will assist in achieving the targets for these metrics. In accordance with Remotes' asset lifecycle optimization policies and practices, the capital upgrade is the more effective method of mitigating the risk compared to costly maintenance.

1.5. Condition of Assets

At Kingfisher Lake, the lack of ventilated airspace at the eaves is causing ice formation at the roof edge, leading to safety risks. To date, Remotes has worked around the issue by connecting temporary ice-stops to the light gauge roof panels, but the fasteners continually pull out of the light gauge material, requiring a great deal of maintenance and compromising the effectiveness of the steel roofing panels.

In Weagamow, ventilation in the attic space is insufficient and there is no air space at the exterior wall locations due to insufficient heel height on the roof trusses. In addition, the roof panels are beginning to show signs of deterioration on the exterior.

1.6. Customer Impact

a) <u>Customer profile for the community:</u>

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	Street Lightning	Std A – Res. – Air	Std A – GS – Air	Total
Community	**Number of Customers**							
Kingfisher Lake	108	-	10	2	-	4	17	**141**
Weagamow	244	-	24	1	1	12	26	**308**

b) <u>Customer impacts for each community:</u>

The table below presents the customer impacts for each community. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Kingfisher Lake	141	649	High
Weagamow	308	1096	High

1.7. Supporting Documentation

The *Diesel Generator Station Roof Assessment Report* is attached as Appendix H to the DSP. Photos of the two stations with upgrades planned in 2018 are provided on the following pages, as excerpted from the report.

Figure 1: Kingfisher Lake Diesel Generating Station (Exterior)

Figure 2: Existing Roof Insulation Thickness (Kingfisher Lake)

Figure 3: Roof Panel Mid-Span & Eave Support (Kingfisher Lake)

Figure 4: Roof Panel Peak Support (Kingfisher Lake)

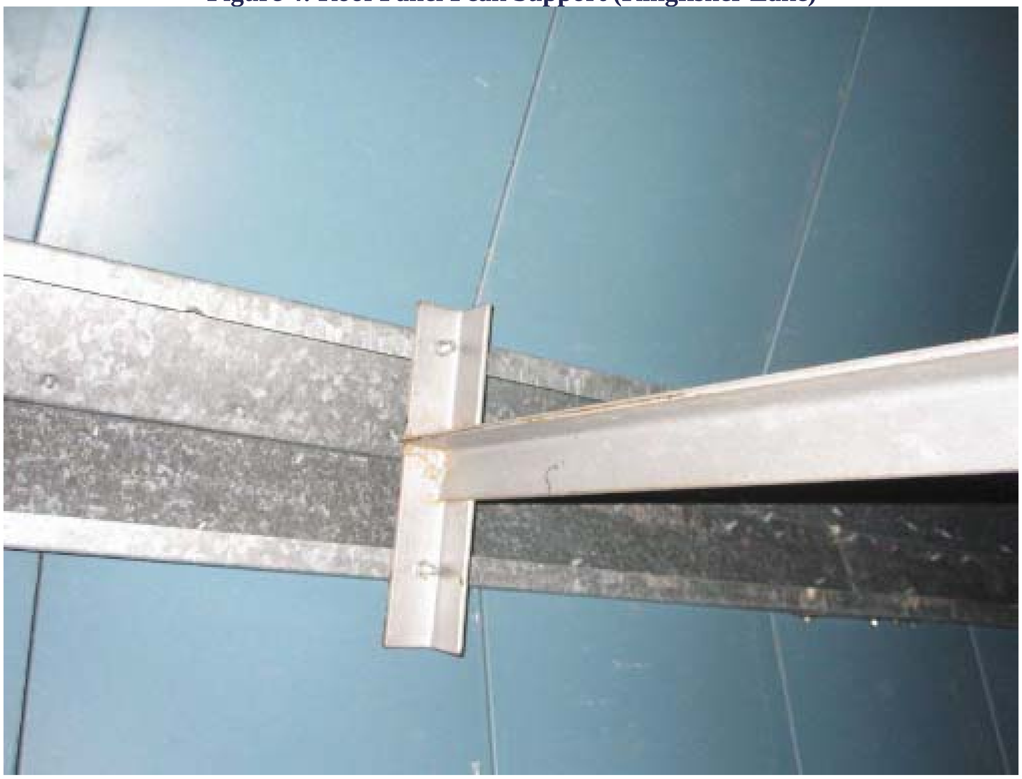


Figure 5: Roof Panel Peak Support (Kingfisher Lake)

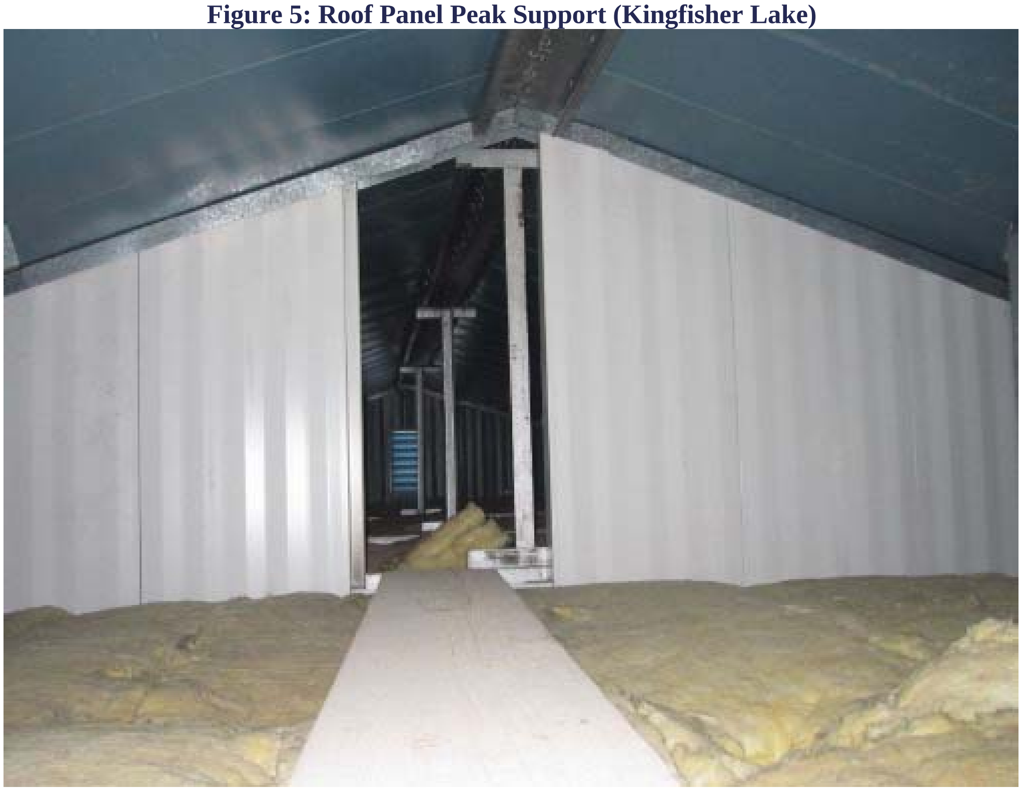


Figure 6: Roof Framing (Weagamow)

Figure 7: CFC Purlins (Weagamow)

Figure 8: Insufficient Air Space (Weagamow)

Figure 9: Beginnings of Visible Ice Formation (Weagamow)

Figure 10: Exposed Fuel Line Tray & Visible Heat Loss (Weagamow)

Figure 11: Visible Heat Loss & Roof Panel Deterioration Signs (Weagamow)

2. Project/Program Justification

2.1. Information Used to Justify the Investment

A report by FORM Architecture Engineering titled *Diesel Generator Station Roof Assessment Report & Recommendations* provides the justification for the investment. The report is included as Appendix H to the DSP.

2.2. Alternatives Evaluation

Alternative 1: Do nothing

The “do nothing” option considers no capital investment or preventative maintenance to the diesel generating stations. Staff and the operator would continue to work in the plant and the safety of these workers would be compromised.

Alternative 2: Preventive maintenance

The icing concerns can be temporarily mitigated using ice-stops connected to light gauge roof panels.

Alternative 3: Build a new diesel generating station

A new station is planned for the community; however, the timing and amount of available INAC funding is uncertain. The station must be in service and usable until a new modular unit is built. When the new station is completed, it is anticipated that most of the old plant will be used for storage. Therefore, the building will still be used and useful.

a) Comparison of Project Alternatives

In the case of the “do nothing” option, the ice formation would pose an unacceptable safety risk at the diesel generating stations. This is not a feasible alternative.

The fasteners installed as part of the preventative maintenance option continually pull out of the light gauge material. This requires costly maintenance to ensure performance. In addition, continual re-attachment of the temporary ice-stop material provides new penetrations through the roof panels and compromises the effectiveness of the roofing material. This is not the preferred alternative.

The alternative to build a new diesel generating station would mitigate the concerns of the existing station but would cost much more than the planned site upgrade. The condition of the remainder of the diesel generating station does not warrant a complete rebuild. This is not the preferred alternative.

The planned upgrades in Kingfisher Lake and Weagamow will mitigate the safety risk of ice formation without requiring costly and ongoing maintenance over the life of the building. The planned upgrade in Weagamow will also improve the insulation to reduce the heat loss from the building. This is the preferred option, as per the recommendations of the *Diesel Generator Station Roof Assessment Report*.

b) Comparison of Project Timing Alternatives

Deferral of the project would mean that the station roofs continue to deteriorate and ice build-up would continue to put staff and operators at risk. More important, the stations where roofs are planned are all old and, at some point, maintenance to keep the integrity of the building intact is required. Deferral of these investments could result in the need for further civil work as the building envelope could be compromised.

c) Analysis of Project Enhancements

Full details of the recommended upgrades planned under this project can be found in Appendix H.

2.3. Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital (Gross)	133	412	250	211	344	346	353	360	368	376
Removals	-	-	-	-	-	-	-	-	-	-
Net Capital	**133**	**412**	**250**	**211**	**344**	**346**	**353**	**360**	**368**	**376**
O&M	-	-	-	-	-	-	-	-	-	-

b) Start Date
April/May 2018

c) In-Service Date
June 30 to July 30, 2018

d) Comparative Expenditure Information

	Forecast Costs ($ '000)			
	Q1	**Q2**	**Q3**	**Q4**
Capital (Gross)	-	173	173	-
O&M	-	-	-	-

e) Comparative Expenditure Information

Comparative information on expenditures for equivalent projects/activities can be found in Section 2.3(a) above. The cost of diesel plant civil improvements depends on the scope of work for each station.

2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

As per the Comparison of Project Alternatives, the alternative to the capital upgrade is preventative maintenance to prevent ice formation at the diesel generating stations. The fasteners installed as part of the preventative maintenance option continually pull out of the light gauge material, therefore the maintenance must be performed continually. The continual reattachment of the temporary ice-stop material provides new penetrations through the roof panels and compromises the effectiveness of the roofing panels. The investment mitigates the structural compromise cost effectively without the need for continuous maintenance.

b) Customer

Customers benefits from the safety improvement in the communities. Since the investment is cost effective compared to continual maintenance over the life of the diesel generating station, ratepayers also benefit from the cost effectiveness of the investment.

c) Safety

The investment will mitigate a safety risk of ice formation at the diesel generating station.

d) Cyber-Security, Privacy

Not applicable to civil upgrades.

e) Co-ordination, Interoperability

This project applies recognized engineering principles based on a third-party report by FORM Architecture Engineering, stamped by a Professional Engineer registered in the Province of Ontario. The report has been included as Appendix H to the DSP. Remotes coordinates with the local Band Councils for upgrades in the communities.

The station in Weagamow is old and is not in good repair. INAC funding for a new plant may become available; however, the scope and timing of INAC funding is uncertain. Once funding is received it will be spread over multiple years for the entire station rebuild. In the interim, the community will continue to require reliable electricity and measures are required to mitigate the safety hazards.

f) Economic Development

The majority of Remotes customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training.

g) Environment

The additional fiberglass insulation at Weagamow diesel generating station will reduce the amount of energy lost to the environment.

h) System Impacts

Not applicable to civil upgrades.

3. Prioritization

3.1. Criteria for Prioritization

This program is measured against the following two risk categories:

1. Financial
2. Safety

a) Financial

Without the planned projects, ice barriers would need to be installed. This is a temporary fix necessitating frequent capital reinvestment. A new roof would eventually be required at Weagamow.

b) Safety

Falling ice is a serious safety risk for operators and staff entering or leaving the generation station.

3.2. Consequences of Deferral

If either project were deferred, falling ice would remain a safety hazard at these stations. Roofs would be subject to further deterioration. Maintenance work to install ice barriers in each of the communities would continue to be required.

3.3. Priority

Civil projects are a lower priority than those that affect community reliability. However, the safety of staff and station operators is also a priority.

4. Execution Path

4.1. Implementation Plan

The project includes insulation and roofing upgrades. The work will be done by experienced construction personnel familiar with building upgrades. The work will be coordinated with other work in the communities, including a planned capacity upgrade of the Weagamow generator. The generator will be procured in 2018 and installed in 2019, therefore the two projects will not interfere with one another.

4.2. Risks and Risk Mitigation

The biggest project risk is the use of in-house labour as the project is labor intensive. It will be managed through regular involvement and oversight by both the civil department and the project planner.

4.3. Timing Factors

The ability to safely fly in crews can affect the timing of this project.

4.4. Cost Factors

The project cost estimate is based on the expected labour hours and material costs, which can vary for civil upgrades in remote communities in northern Ontario. The net spending on the Weagamow generating station improvements depends on the capacity upgrade project in Weagamow. If the civil plant is replaced as part of the upgrade, then the cost would be recoverable through INAC.

4.5. Customer Preferences

Poor condition of the generating station can cause an increase in outages and reduce reliability.

4.6. Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

SCADA & PLC Replacements

1. Project/Program Description

1.1. Current Issue

This program seeks to upgrade the Supervisory Control and Data Acquisition ("**SCADA**") and Programmable Logic Controller ("**PLC**") systems deployed in the Remotes' generating stations along with telecommunications equipment used to monitor the operation of this equipment. The PLC and SCADA equipment currently in use are, on average, nearly 20 years old. New replacement parts to conduct repairs are no longer available given the models' obsolescence, while used parts are increasingly difficult to procure. Moreover, the Compact TSX PLC equipment is near its maximum memory storage capacity and lacks the spare input/output points that could enable temporary upgrades. Current site connectivity (required for remote monitoring and operation) is provided by obsolete dial-up modem technology, with significant speed and reliability implications.

1.2. Project Scope

The planned replacements, targeted for the 2018 Test Year include satellite or fibre optic communications equipment and SCADA upgrade at Armstrong, Gull Bay, Kingfisher Lake, Sachigo Lake, and Weagamow, along with the PLC unit upgrade at Armstrong.

1.3. Main and Secondary Drivers

As per Table 1-1 in Remotes' DSP, system reliability and operational efficiency are the main drivers for the planned communication, SCADA and PLC upgrades.

1.4. Performance Targets and Objectives

The PLC and SCADA systems are integral to efficient and reliable operation in the Remotes service territories – automation of Remotes generator equipment to follow communities' load profiles throughout the day has enabled the company to achieve a 10% improvement in fuel efficiency. Furthermore, real-time monitoring of generator station equipment permits Remotes to quickly identify station failures such as outages or fuel spills, resulting in better system reliability and environmental protection through faster issue identification and response, along with ensuing benefits to the related corporate performance measures.

1.5. Customer Impact

a) <u>Customer profile for the community:</u>

The following table showcases the number and rate classification of customers in the communities targeted for upgrades:

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	SL	Std A – Res. – Road	Std A – GS – Road	Std A – Res. – Air	Std A – GS – Air	Total
Community		Number of Customers								
Armstrong	240	39	58	6	2	5	12	-	-	**362**
Gull Bay	86	-	8	-	-	3	9	-	-	**106**
Kingfisher Lake	108	-	10	2	-	-	-	4	17	**141**
Sachigo Lake	131	-	14	1	1	-	-	5	13	**165**
Weagamow	244	-	24	1	1	-	-	12	26	**308**

b) Customer impacts for each community:

The table below presents the customer impacts for each community, including the expected outage duration and frequency without the planned project. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50 seasonal customers

Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Armstrong	362	1035	Medium
Gull Bay	106	334	High
Kingfisher Lake	141	649	High
Sachigo Lake	165	718	High
Weagamow	308	1096	High

1.6. Supporting Documentation

Remotes is in the process of equipping all of its generating stations towards a standard equipment set-up consisting of:

- Fiber or satellite telecommunications equipment.
- M340 – BMXP342020 or M580 PLC hardware with firmware version 10.0.
- Momentum – 171-CBU-980-90 PLC hardware with firmware version 10.0.
- Small PC – SDC170 touchscreen or desktop PC IFix hardware.
- Windows 7 Pro and IFix 5.8 software with Proficy Historian

Establishing a standard equipment complement in each community is expected to simplify the maintenance, repairs/replacements, and incident response efforts throughout the Remotes' service territory, thereby positively impacting the company's servicer levels while managing the aggregate costs.

The following table summarizes the existing equipment at each generating station. The existing solutions are over 10 years old. Remaining with the current configuration will increase risk due to the lack of replacement parts and outdated software.

Site	Telecom.	PLC		IFix	
		Hardware	Firmware	Hardware	Software
Thunder Bay	Fibre internet	N/A	N/A	Virtual Machine Virtual Machine	Windows 7, IFix 5.8 Proficy Historian, Webspace
Armstrong	Dial-up	TSX Compact – PC-E984-275 Momentum	2.6 SR3 2.6 SR3	INX Panel PC	Windows NT4, Fix
Bearskin	Dial-up	TSX Compact – PC-E984-275 Momentum	2.2 SR2 2.2 SR2	INX Panel PC	Windows NT4, Fix
Big Trout	Dial-up – fibre upgrade soon	TSX Compact – PC-E984-275 Momentum	2.2 SR2 2.2 SR2	INX Panel PC	Windows NT4, Fix
Biscotasing	Dial-up	TSX Compact – PC-E984-275 Momentum – 171 CCC 760 10 & 00	2.2 SR2 2.2 SR2	INX7000 Panel PC	Windows NT4 SP6, Fix
Deer Lake	Satellite	Quantum – 140-CPU-113-03S Momentum	2.6 SR3 2.6 SR3	Desktop PC	Windows XP, IFix 3.5
Deer Lake Hydel	Satellite	Quantum – 140-CPU-534-14 (Spare) Momentum	2.6 SR3 2.6 SR3	Touch Panel PC	Windows NT4, Fix 7.0
Fort Severn	Dial-up	TSX Compact – PC-E984-275 Momentum	2.6 SR3 2.6 SR3	INX6000 Panel PC	Windows NT4, Fix
Gull Bay	Dial-up	TSX Compact – PC-E984-275 Momentum	2.2 SR2 2.2 SR2	Desktop PC & Panel PC	Windows XP, Fix
Hillsport	Dial-up	TSX Compact – PC-E984-275 Momentum	2.6 SR3 2.6 SR3	INX Panel PC	Windows NT4, Fix
Kasabonika	Dial-up – fibre upgrade soon	Quantum – 140-CPU-434-12A Momentum – 171-CBU-980-90	8.0 8.0	Desktop PC & iEi Touchscreen	Windows 7, IFix 5.5
Kingfisher	Dial-up	TSX Compact – PC-E984-275 Momentum – 171 CCC 760 10	2.6 SR3 2.6 SR3	INX6000 Panel PC	Windows NT4, Fix32 V 7.0
Lansdowne	Dial-up	TSX Compact – PC-E984-275 Momentum	2.2 SR2 2.2 SR2	INX Panel PC	Windows NT4, Fix
Marten Falls	Satellite	Quantum – 140-CPU-434-12	2.6 SR6	Desktop PC	Windows XP Pro SP3, IFix

Site	Telecom.	PLC		IFix	
		Hardware	Firmware	Hardware	Software
		Momentum – 171 CCC 760 10 Momentum – 171 CCC 960 30 & 10	2.6 SR6 2.6 SR6		5.0 SP2
Oba	Dial-up	TSX Compact – PC-E984-275 Momentum – 171 CCC 760 10 & 00	2.6 SR3 2.6 SR3	INX7000 Panel PC	Windows NT4 SP6, Fix32 V 6.1
Sachigo	Dial-up	TSX Compact – PC-E984-275 Momentum	2.2 SR2 2.2 SR2	INX Panel PC	Windows NT4, Fix
Sandy Lake	Satellite	Quantum – 140-CPU-434-12 Momentum	2.6 SR3 2.6 SR3	Desktop PC	Windows XP, Fix32 V 7.0
Sultan	Dial-up	Quantum – 140-CPU-534-14 Momentum – 171 CCC 960 30	2.6 SR3 2.6 SR3	Dell Optiplex GX50	Windows NT4, Fix32 V 7.0
Wapekeka	Dial-up – fibre upgrade soon	TSX Compact – PC-E984-275 Momentum	2.6 SR3 2.6 SR3	INX Panel PC	Windows NT4, Fix
Weagamow	Dial-up	TSX Compact – PC-E984-275 Momentum	2.6 SR6 2.6 SR6	INX Panel PC	Windows NT4, Fix
Webequie	Satellite	Quantum – 140-CPU-434-12 Momentum	2.6 SR3 2.6 SR3	Desktop PC	Windows XP, IFix 5.1

2. Project/Program Justification

2.1. Information Used to Justify the Investment

Remotes' PLC and SCADA systems were originally installed between 1998 and 2000, and vendors no longer support the existing equipment and software. In the event of failure, the Remotes personnel rely on internal expertise and available spare equipment to rectify the issues as they arise. As the existing equipment continues to age, the probability of its failure (across a variety of potential causes) continues to increase, thereby increasing the risk to continuous system operations at an acceptable standard.

2.2. Alternatives Evaluation

Alternative 1: Do nothing

The "do nothing" alternative entails no SCADA or PLC upgrades, and the current configurations are used at Remotes' substations.

Alternative 2: SCADA and PLC replacement at another station

This alternative assumes that SCADA and PLC upgrades at other stations than those planned in the 2018 Test Year where these upgrades could ostensibly be justified.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, functionality and system capability are expected to be significantly reduced going forward. This is not the preferred alternative.

To compare various stations for upgrades, the following metrics were considered:

- Remoteness: distance from the service centre (Thunder Bay).
- Population of the community.
- Availability of auxiliary power for the communication, SCADA, and PLC systems.
- Reliability of existing communication systems.

The annual project priorities are based on the worst performing station infrastructure. Each metric above was given a composite index rating on the basis of the above criteria. The outcome of the rankings was used to prioritize the stations. The following table summarizes the results of the analysis.

Community	Remoteness	Population	Aux. Power	Comm. Reliability	Total
Big Trout	17	19	0	2	38
Sandy Lake	15	20	1	1	37
Fort Severn	20	10	0	5	35
Bearskin	19	13	0	2	34
Sachigo	18	12	0	2	32
Wapekeka	16	11	0	5	32
Deer Lake	14	15	1	1	31
Kasabonika	13	16	0	2	31
Weagamow	12	17	0	2	31
Deer Lake Hydel	14	15	0	1	30
Armstrong	3	18	0	4	25
Webequie	10	14	0	1	25
Kingfisher	11	9	0	2	22
Marten Falls	8	8	1	1	18
Lansdowne	9	6	0	2	17
Bisco	7	5	0	2	14
Sultan	6	4	0	2	12
Gull Bay	2	7	0	2	11
Hillsport	4	3	0	2	9
Oba	5	2	0	2	9

b) Comparison of Technically-Feasible Alternatives

Communications infrastructure alternatives include fibre, satellite, and dial-up internet. Fibre is the most reliable and flexible technology, since it is available consistently and offers the most bandwidth. Satellite offers intermittent but successful communications. Dial-up is the least effective, since there is limited bandwidth and availability is affected by power outages in other communities. The preferred communications infrastructure was selected based on available technologies within the communities, with the elimination of dial-up considered the highest priority. In the fly-in communities, there is only a single provider of fibre infrastructure. Fibre infrastructure is installed where available, otherwise satellite communications is used. Canadian satellite communication providers are limited to a sole source tailoring to the industrial environment with a proven track record.

The SCADA and PLC technology was chosen for compatibility with existing systems to reduce training costs and changes to existing infrastructure.

2.3. Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017*	2018	2019	2020	2021	2022
Capital (Gross)	-	-	-	-	413	505	726	675	391	353
Removals	-	-	-	-	-	-	-	-	-	-
Net Capital	**-**	**-**	**-**	**-**	**413**	**505**	**726**	**675**	**391**	**353**
O&M	-	-	-	-	-	-	-	-	-	-

*0 months of actual expenditures included in 2017

b) Start Date
January 1, 2018

c) In-Service Date
December 31, 2018

d) 2018 Test Year Expenditure Timing

	Forecast Costs ($ '000)			
	Q1	Q2	Q3	Q4
Capital (Gross)	126.25	126.25	126.25	126.25
O&M	-	-	-	-

e) Comparative Expenditure Information

There are no equivalent historical projects of this nature.

2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

The SCADA and PLC systems are key to ensuring the operational efficiency of the generators.

b) Customer

This investment affects system reliability, by allowing real-time monitoring of the station.

c) Safety

A functional and up-to-date SCADA system allows Remotes' personnel to accurately assess any issue which may arise, thus improving employee and public safety.

d) Cyber-Security, Privacy

In accordance with the NIST Guide to Industrial Control Systems Security, the planned upgrade includes restrictions of physical access to the station, PLC monitoring to detect security events, a demilitarized zone ("**DMZ**") network architecture, and restrictions of unauthorized remote access.

e) Co-ordination, Interoperability

Remotes coordinates with Band Councils concerning new investments. The investment enables future operational requirements at the generating stations in question.

Interoperability and compatibility are incorporated into the design.

f) Economic Development

Most of Remotes' customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training.

g) Environment

The SCADA and PLC upgrades are expected to improve the company's fuel efficiency and enhanced ability to quickly identify fuel spills.

3. Prioritization

3.1. Criteria for Prioritization

This program is measured against the following four risk categories:

1. Customer/reliability
2. Financial
3. Efficiency
4. Environment

a) Customer/reliability

Currently, a SCADA system breakdown requires manual agent operation of the generating equipment. Outage information is no longer available, leading to longer outages. SCADA information is necessary for troubleshooting the cause of generation station outages. When operator intervention is required, communication is improved with SCADA information.

Outages related to a PLC failure can normally be cleared in less than an hour. The frequency of outages increases due to PLC failures. Lack of connectivity reduces knowledge of outage cause, reducing ability to troubleshoot problems remotely. Also, customers may need to call before an outage is detected.

b) Financial

The PLC controls many plant interactions, including general selection and power output. Operators can run the plant manually; however, this is difficult and inefficient. Troubleshooting will likely be necessary to return the plant to operation. PLC troubleshooting would require a flight ($5000) and labour hours.

c) Efficiency

The estimated benefit of the overall SCADA and PLC system is a 10% increase in fuel efficiency. Fuel tanks are monitored via the SCADA system. Spill alarms are also connected to the SCADA system. Response to spill events could be delayed, increasing the scope and cost of rectification efforts.

d) Environment

Absent the planned program, generation emissions would be higher due to the reduced generator efficiency. A SCADA malfunction may results in a longer response time in case of a spill, which increases the risk of contaminants leaking into the environment.

3.2. Consequences of Deferral

Automation of the plants and an ability to monitor performance is critical to investigate the cause of outages. Without reliable communications, SCADA, and PLC systems, Remotes would be unable to perform preventative maintenance, troubleshooting, and rapid event notification. Furthermore, plant operation will change from automated to operator manual operation.

3.3. Priority

The project has been staged over several years. Improving the SCADA system provides necessary access to operational information to improve and maintain current operations. Failures of the PLC system require manual intervention, which can require flights and labour hours.

4. Execution Path

4.1. Implementation Plan

This investment consists of a three-part process:

1. Upgrade Communications

   Addition of satellite or fibre wide-network connectivity. Fibre is the preferred choice due to the speed and reliability advantage over satellite. Where fibre is not available, satellite can be incorporated.

2. Upgrade SCADA hardware and software

   To take full advantage of the upgraded communications, the SCADA systems need to handle the increased bandwidth. New hardware and software will be procured, configured, installed, and commissioned. Cyber-security, compatibility, and capacity will be incorporated in the design.

3. Upgrade PLC hardware and software

   To combat the memory capacity and the lack of input/output expandability as well as utilizing new Ethernet communication, PLC hardware replacement will occur. Each upgraded PLC will mirror the existing software.

The projects are also coordinated with other work planned at the generating stations. In 2018 civil plant upgrades are planned at the Weagamow and Kingfisher Lake diesel generating stations.

4.2. Risks and Risk Mitigation

The greatest risks to completing this program as planned relate to timing and cost factors, as described below.

4.3. Timing Factors

The ability to safely fly in crews are can affect the timing of this investment. To mitigate this risk, Remotes can work around the weather to complete the work earlier or later in the year.

4.4. Cost Factors

For complex system upgrades such as SCADA, PLC, and communication upgrades, the largest factor affecting the final cost of the project is cost of labour. The number of personnel depends upon the testing and commissioning requirements of each system to ensure compatibility among the various components. Since 2017 is the first year of this program, these costs are not well known. Controllable costs are minimized through extensive vendor participation prior to project rollout. By using similar systems for the different generating stations, Remotes also reduces the installation, testing, and commissioning costs.

4.5. Customer Preferences

In Remotes' latest customer survey in 2015, 65% of respondents stated that a reliable source of electricity is a key driver to their satisfaction. Modern engines have critical engine data available to be interfaced with the PLC and SCADA, providing the company with a better picture of the state of the plant. This information enables the maintenance staff to analyze and solve problems without undue delay, thereby managing the number of equipment interruptions.

Environmental protection is also important to Remotes' customers as identified in Remotes' 2016 Customer Workshop. This project improves diesel fuel efficiency, reducing the environmental impact of the diesel generation.

4.6.Regional Electricity Infrastructure Requirements

Given the nature of Remotes' operations, this project is not driven by any regional electricity infrastructure requirements. The 2016 Order-in-Council by the Minister of Energy identified 16 communities which are expected to be connected to new transmission lines passing through northern Ontario, including Sachigo Lake, Kingfisher Lake, and North Caribou Lake (Weagamow). The Remote Community Connection Plan is still in its draft form until further community consultation is performed and the anticipated connection date of this community is not known.

4.7.Incorporation of Advanced Technology

The project incorporates advanced SCADA, communications, and PLC technology.

4.8. Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Big Trout Lake and Wapekeka Connection and Upgrade

1. Project/Program Description

1.1.Current Issue

The peak station load at Big Trout Lake reached 1395 kW in 2015, which exceeds the 1360-kW connection limit. The community of Wapekeka currently does not have new customer connection restrictions in place, but the peak load has reached 643 kW, which represents 74% of the station rating. Given that the Order-in-Council by the Minister of Energy has identified these two communities to be connected to new transmission lines at an undecided date in the future, Remotes' customers have requested funding through INAC to connect these two communities and perform upgrades at the generating stations to facilitate the connection, in the manner discussed in this document. The planned of the two communities is expected to increase the combined system capacity.

1.2. Project Scope

The scope of work includes an upgrade of the generation stations in Big Trout Lake and Wapekeka and a new 22-km, 25-kV overhead line linking the communities of Kitchenuhmaykoosib Inninuwug (Big Trout Lake) and Wapekeka First Nations, that is planned to address the load growth in both communities. Planning and design work for this project commenced in 2015.

The unit chosen to be replaced is the smallest generating unit in the combined generating station, namely the C unit in Wapekeka with 410 kW of capacity, as it will be too small to carry the lowest load level of the combined communities. It will be exchanged for a 1500-kW unit, increasing the combined station rating to 3765 kW. Upon replacement, the original generating unit would go back into inventory to be deployed in another community.

The planned scope of work would increase the station transformation capacity in each community to 3000 kW. Once construction is complete, this project would remove new customer connection restrictions in the Kitchenuhmaykoosib Inninuwug community, and enable unconstrained customer connections in both communities for five to ten years. The planned work is 100% recoverable through funding agreements with the First Nations and INAC.

The distribution system equipment in question was procured earlier in 2017. Generation equipment is planned to be purchased in 2018 and 2019. Modifications to the Wapekeka Generation Station are planned to commence in 2018. Big Trout Lake generating station modifications are planned for 2019. Testing and integration would ensue prior to putting the unit into service in 2020.

Additionally, 67.5 kW of community-owned solar, requested by customers and to be placed on related non-Standard A accounts, is planned as part of the project.

1.3. Main and Secondary Drivers

The driver for generator upgrade investments, as per Table 1-1 of Remotes' DSP, is system capacity constraints (i.e. expected changes in load that will constrain the ability to the system to provide consistent delivery). The peak load in Big Trout Lake has surpassed the connection limit (85% of the station rating) and should therefore be upgraded immediately.

Big Trout Lake and Wapekeka are 22 km apart and connected by a road. Connecting the two generating stations would decrease the combined peak load and thus result in a more efficient system. Furthermore, the connection between these two communities will be necessary once the new transmission lines reach the communities.

1.4. Performance Targets and Objectives

The investment affects a number of performance targets listed in Remotes' DSP. The connection of the two communities would improve the ability to supply power from either diesel generating station under contingency situations, reducing the frequency and duration of outages in both communities. As discussed in Section 2.3.1.1 of Remotes' DSP, system reliability is a key driver to customer satisfaction. The proposed upgrade of Wapekeka C would reduce the probability of its unplanned failure and thus improve reliability and generator availability. By connecting the two distribution systems, the load can be managed more efficiently using the Programmable Logic Controller (PLC) technology to improve diesel generation efficiency.

The proposed project is expected improve operational efficiency and cost effectiveness. For a project this size, 375,000 litres of additional fuel tanks would normally be required and purchased. In this case, only 150,000 litres of new fuel tanks are planned to be purchased in Wapekeka as part of this project. Both First Nations currently have fuel storage at their respective airports. To make up for the required fuel storage, each First Nation has agreed to sell fuel to Remotes and to dedicate a tank to Remotes.

A notable drawback of these improvements is an increase distribution losses are expected to increase with the addition of the new line (line losses are proportional to distance). However, the benefits associated with the improvements to system operability and reliability offered by the proposed investments exceed the impact of the associated increase in losses.

Remotes manages its diesel generating stations by limiting the peak load at the station to 85% of the station's rating (known as the connection limit). By connecting the two communities and upgrading unit C at Wapekeka, the system constraints will be removed and the planning objectives will be improved in both communities in the future.

1.5.Customer Impact

a) Customer profile for the community:

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	Street Lightning	Std A – Res. – Air	Std A – GS – Air	Total
Community	**Number of Customers**							
Big Trout Lake	301	-	30	6	-	10	50	**397**
Wapekeka	114	-	10	1	-	5	20	**150**

b) Customer impacts for each community:

The table below presents the customer impacts for each community. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10% and 50% seasonal customers.
- Low – greater than 50% seasonal customers

Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Big Trout Lake	397	1395	High
Wapekeka	150	643	High

2. Project/Program Justification

2.1. Information Used to Justify the Investment

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load in Big Trout Lake and Wapekeka for the years 2017 through 2022 are listed in kW in the table below. The forecast is based on the actual peak load observed in 2016.

Community	Connection Limit (kW)	Peak Load Forecast (kW)					
		2017	2018	2019	2020	2021	2022
Big Trout Lake	1360	1381	1436	1493	1553	1615	1680
Wapekeka	735	651	670	691	711	733	755
Combined	N/A	**2032**	**2106**	**2184**	**2264**	**2348**	**2435**

2.2. Alternatives Evaluation

Alternative 1: Do nothing

The “do nothing” option entails the case where no upgrades are made at either station and the new distribution line is not built.

Alternative 2: Upgrade of both systems without new connection

This option considers the ability to upgrade both systems individually

a) Comparison of Project Alternatives

In the case of the “do nothing” option, Remotes would have to ignore the request of its customers for this project to proceed, contrary to the company’s values and operating principles. Furthermore, under the “do nothing” scenario, connection restrictions would persist indefinitely in Big Trout Lake, and materialize in Wapekeka in the next five years. These considerations render the “do nothing” option suboptimal.

In the case of the second alternative – upgrading both systems individually without the new connection, the upgrade in Wapekeka could be deferred until 2022 or later based on the projected load growth in the community. Instead, the project would upgrade one of the generators in Big Trout Lake immediately, which would be costlier than upgrading the smaller generator in Wapekeka. The isolated systems are less robust when responding to contingency situations than a combined system. Furthermore, the new distribution line will be necessary once the anticipated new transmission connection project reaches the communities. Therefore, Alternative 2 is also suboptimal given its inferior cost effectiveness in light of the anticipated developments over the assets' lifetimes.

Accordingly, the proposed option represents an optimal trade-off between benefits and costs. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option.

b) Comparison of Technically-Feasible Alternatives

The option to build an underground distribution line rather than the overhead distribution line connecting the two communities is a technically-feasible alternative to this project. The cost of construction for an underground distribution line in an area of mostly-frozen soil is much more expensive than an overhead build; therefore, an overhead line was planned.

For a project this size, 375,000 litres of additional fuel tanks would normally be required and purchased. In this case, only 150,000 litres of new fuel tanks are planned to be purchased in Wapekeka as part of this project. Both First Nations currently have fuel storage at their respective airports. To make up for the required fuel storage, each First Nation has agreed to sell fuel to Remotes and to dedicate a tank to Remotes.

2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017***	**2018**	**2019**	**2020**	**2021**	**2022**
Capital (Gross)	-	-	8	137	996	2,149	3,252	1,364	-	-
Contributions	-	-	(8)	(123)	(896)	(1,934)	(2,927)	(1,228)	-	-
Removals	-	-	-	(14)	(100)	(215)	(325)	(136)	-	-
Net Capital	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-

*0 months of actual expenditures included in 2017

b) Start Date
Distribution material purchased in 2017
Generation purchases in 2018 and 2019

c) In-Service Date
June 2020

d) 2018 Test Year Expenditure Timing

	Forecast Costs ($ '000)			
	Q1	**Q2**	**Q3**	**Q4**
Capital (Gross)	537.25	537.25	537.25	537.25
O&M	-	-	-	-

e) Comparative Expenditure Information

Remotes has never previously tied stations together in the proposed manner – the project was conceived in response to limited availability of INAC funds and the goal of the communities to connect new customers in the near term.

2.4. Benefits

a) Operational Efficiency and Cost Effectiveness

By providing a solution that relieves connection constraints in Big Trout Lake and alleviates medium-term capacity concerns in Wapekeka without requiring a generator upgrade in Big Trout Lake, this project is expected to enhance the operational efficiency and cost effectiveness. Notwithstanding the near-term objectives, the proposed distribution line will be required once the communities are connected to the transmission system and, therefore, represents a cost-effective means of relieving the capacity issue and improving reliability of supply in both communities in the interim. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

b) Customer

This project was initiated by Remotes' customers, who benefit through relief of capacity constraints and the improved reliability of the new system. The First Nations will also benefit from increased economic activity associated with the sale of fuel to Remotes and from the installation of community-owned solar generation.

c) Safety

The investment is not expected to negatively impact health and safety protections and performance, as all applicable construction safety standards and operating clearance requirements will be met. The new distribution line will be constructed using Remotes' standards for distribution line construction, compliant with *O. Reg. 22/04*.

d) Cyber-Security, Privacy

In accordance with the NIST Guide to Industrial Control Systems Security, the planned upgrade includes restrictions of physical access to the station, PLC monitoring to detect security events, a demilitarized zone ("**DMZ**") network architecture, and restrictions of unauthorized remote access.

e) Co-ordination, Interoperability

As with all generation upgrade projects, Remotes is working closely with the First Nation communities through the funding allocation and design approval process. When a community's load levels begin to approach their connection limits, Remotes collaborates with the community to identify possible solutions to alleviate the capacity constraints. If a generator upgrade project is required, customers requests the project from Remotes, who works with the community to secure the requisite INAC funding. Under the terms of the electrification agreements, INAC is responsible for funding generation capital upgrades associated with load growth in First Nation communities served by Remotes. The funding must be requested by the communities, but Remotes also works closely with INAC in relation these projects. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

Kitchenuhmaykoosib Inninuwug and Wapekeka First Nations are both anticipating connection to new transmission lines that will reach the area. This has been coordinated into the project plan, since the new distribution line will be required once the transmission lines reach these communities.

f) <u>Economic Development</u>

Most of Remotes' customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment will relieve system capacity constraints in two communities and build a more robust electrical system for the communities, which is conducive to economic growth. The communities will also benefit from the ability to sell fuel and electricity to Remotes and from the ability to perform forestry work that will be required on the line.

g) <u>Environment</u>

Part of the project scope will replace a generator in Wapekeka and newer generators are more fuel efficient. The project will also upgrade the transformation at both diesel generating stations and the new transformers will meet the latest standards in energy efficiency. In addition, planned community-owned solar generation is expected to reduce environmental impacts.

3. Prioritization

This is a non-discretionary project, since it is requested by customers and funded by INAC. The project takes priority over discretionary projects/programs.

4. Execution Path

4.1. Implementation Plan

The program is planned to proceed over six years. It commenced in 2015 and will finish in 2020. Design and material procurement (poles, cable, station transformers, switchgear and building extension) of distribution and generation equipment will take place in 2018. Installation and commissioning of equipment will then be performed in 2019 and 2020. The generating station work will be done by a dedicated station crew, whereas line construction is expected to be tendered by the First Nation and INAC.

This project will be coordinated with other work planned in the communities, including generator replacements in Big Trout Lake from 2018 to 2020. Wherever possible, station crew utilization will be optimized between the two projects to reduce costs.

4.2. Risks and Risk Mitigation

The primary risk factor underlying this project and other generator upgrades is funding from INAC. On a number of past occasions, INAC was unable to support projects due to a lack of funds in light of competing priorities. Without the funding from INAC, Remotes does not have the means to recover the costs for this project and the project would not proceed. To mitigate this risk, Remotes works closely with the communities it serves and with INAC to ensure sufficient funds are available and approved to carry out the work.

Another risk to project completion is the ability to transport heavy electrical equipment to the sites, which requires use of winter roads. To mitigate this risk, the generator and transformers are procured in advance to prepare for transportation. In case an entire season passes without safe winter roads, the project may require deferral. Remotes has the option of hiring specialized aircraft to deliver the equipment if the risk of project deferral is greater than the increased transportation cost.

Remotes has lodgings for only one crew in each community. Therefore, a risk to project completion as planned includes the availability of accommodation for crews to perform work on the generation and distribution systems as part of this project, as well as emergency work that comes up throughout the year. Remotes mitigates this risk through careful project planning and execution. Remotes also has the option to locate crews in both communities (Big Trout Lake and Wapekeka) and to rent temporary accommodation if necessary.

Line construction is expected to be tendered by the First Nation and INAC and is, therefore, outside of Remotes' control.

4.3. Timing Factors

Winter road availability and the ability to safely fly in crews are factors that may affect the timing of this investment. Should this occur, the project may be deferred due to transportation or INAC funding delays, which Remotes attempts to are mitigate through project planning and coordination. Besides these factors, the project is customer-initiated and externally-funded and, therefore, takes priority over discretionary projects/programs.

4.4. Cost Factors

A large part of the final cost of this project will be transportation cost. The access to communities in question makes shipping both difficult to coordinate and expensive.

4.5.Customer Preferences

This project was initiated by Remotes' customers. As identified in Section 2.2.1.1 of Remotes' DSP, customers prioritize renewable energy. As such, the customer-requested scope includes 67.5 kW of community-owned solar generation.

4.6.Regional Electricity Infrastructure Requirements

The 2016 Order-in-Council by the Minister of Energy identified 16 communities which will be connected to new transmission lines passing through northern Ontario, including Kitchenuhmaykoosib Inninuwug (Big Trout Lake) and Wapekeka. The Remote Community Connection Plan is still in its draft form until further community consultation is performed and the anticipated connection dates of these communities are not known. In anticipation of the new transmission lines, the new distribution line is being constructed as an integrated, cost-effective approach to increase the capacity of both communities, as well as improving the robustness of the electricity supply. The new distribution line will be required to connect the communities to the new transmission line

4.7. Incorporation of Advanced Technology

N/A

4.8. Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Sandy Lake Upgrade

1. Project/Program Description

1.1. Current Issue

The peak station load at Sandy Lake reached 2576 kW in 2013, nearing its connection limit of 2593 kW or 85% of the station capacity (3050 kW). Based on the current loading levels, the peak load is forecast to exceed the connection limit by 2018. Therefore, Remotes' customers have requested funding through INAC to upgrade the generating station capacity in Sandy Lake. The timing of the generation investment depends on INAC approval for the capital dollars that is presently outstanding. For planning purposes, Remotes' anticipates that the required INAC investment will be made in time to enable continued community growth (that is, 2018). Given that the investment constitutes contributed capital, there is no impact to Remotes' rate base.

1.2. Project Scope

There are currently four low-speed (1200-rpm) diesel generators in Sandy Lake. G1 and G2 each have a rated capacity of 1250 kW, G3 is rated 1500 kW, and G4 is rated 1000 kW. The G1, G2, and G4 units have all been in service since 2008, whereas G3 was installed in 2013. For the upgrade, the unit with the lowest capacity, namely G4, was chosen to be exchanged for a 1500 kW unit, increasing the station's aggregate rating to 3300 kW. The chosen generator has operated for the most engine-hours of the four generators.

The existing transformation capacity is sufficient to serve the load. The existing station building and generator rooms were designed to accommodate incremental community load growth and, as such, do not require any facilities expansion investments accommodate the new generator. Some modifications to the controls may be required as part of this project.

1.3. Main and Secondary Drivers

The driver for generator upgrade investments, as per Table 1-1 in the DSP, is system capacity constraints (i.e. expected changes in load that will constrain the ability to the system to provide consistent delivery). Sandy Lake's peak load is forecast to exceed the station's connection limit in 2018 and as such, requires an upgrade to enable continued load growth. This forecast is based on historical data that has determined the future annual load increase in Sandy Lake to be around 2.5%.

1.4. Performance Targets and Objectives

Remotes manages its diesel generating stations by limiting the peak load at the station to 85% of the station's rating before commencing the analytical work and engagements underlying potential expansion planning. By upgrading the G4 unit at Sandy Lake, the system constraints would be relieved.

The proposed investment would also positively affect several performance targets listed in Remotes' DSP. The upgrade of Sandy Lake G4 would reduce the probability of its unplanned failure and thus improve reliability and generator availability. By replacing the old generator with a new one that meets the latest energy efficiency standards, both diesel generation efficiency and carbon emission intensity would be positively affected.

1.5. Customer Impact

a) Customer profile for the community:

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	Street Lightning	Std A – Res. – Air	Std A – GS – Air	Total
Community	**Number of Customers**							
Sandy Lake	440	-	29	3	1	21	26	**520**

b) Customer impacts for the community:

The table below presents the customer impacts in Sandy Lake. The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10 and 50% seasonal customers.
- Low – greater than 50% seasonal customers

Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Sandy Lake	520	2576	High

2. Project/Program Justification

2.1. Information Used to Justify the Investment

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load in Sandy Lake for the years 2017 through 2022 is shown below in kW. The forecast is based on the 2016 actual peak load.

Community	Connection Limit (kW)	Peak Load Forecast (kW)					
		2017	**2018**	**2019**	**2020**	**2021**	**2022**
Sandy Lake	2593	2535	2598	2663	2730	2798	2868

Since the load is anticipated to reach the connection limit in 2018, the station should be upgraded around that time to avoid connection restrictions.

2.2. Alternatives Evaluation

Alternative 1: Do nothing

Given the nature of the Remotes' service territory and the ensuing mode of operation, the "do nothing" option considers the case where no upgrade is made at the station.

Alternative 2: New hydroelectric generation

This alternative considers the option of the Sandy Lake First Nation developing a new hydro-electric generating facility (the "**Duck River Dam**") to relieve system capacity.

a) Comparison of Project Alternatives

In the case of the "do nothing" option, Remotes would have to de-prioritize the request from its customers for this project to proceed (at least for a certain period of time), contrary to Remotes' values. Furthermore, connection restrictions are expected to occur in Sandy Lake in the next two years. This is not the preferred option.

The Sandy Lake First Nation is interested in developing the Duck River Dam; however, they have not yet been able to secure approvals from the province or the federal government to develop this project and are not expecting to resolve this issue within the timeline when the anticipated connection constraints would materialize. Accordingly, the project timelines would not address the short-term supply needs of the community. This is not the preferred alternative

The proposed project is the preferred alternative. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option.

b) Comparison of Technically-Feasible Alternatives

The generator selected for the upgrade at Sandy Lake is both the smallest and has run for the most hours. Therefore, the upgrade of this particular unit is optimal from within the range of available options of proactively addressing the impending capacity shortages. The existing transformation at the generating station is sufficient to meet the capacity needs. Some modifications to the controls may be required as part of this project.

Rather than requesting an increase to tank storage, Remotes expects to purchase more fuel from the Sandy Lake Tank Farm.

2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017***	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	-	-	-	-	-	367	881	1,311	-	-
Contributions	-	-	-	-	-	(330)	(793)	(1,180)	-	-
Removals	-	-	-	-	-	(37)	(88)	(131)	-	-
Net Capital	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-

*0 months of actual expenditures included in 2017

b) Start Date
Design in Q3 of 2018
Purchase engine in 2019
Transport by winter road in March 2020

c) In-Service Date
July 31, 2020

d) 2018 Test Year Expenditure Timing

	Forecast Costs ($ '000)			
	Q1	Q2	Q3	Q4
Capital (Gross)	-	-	183.5	183.5
O&M	-	-	-	-

e) Comparative Expenditure Information

The planned total cost of this investment is $2,559,000, spread over three years. In order to compare the cost to other station upgrade investments, cost per kW has to be considered. The new unit has 1500 kW capacity, rendering the cost per kW at $1,706.

A station upgrade was done in Deer Lake in 2016, where a new 1200-rpm generator unit with capacity 1500 kW was installed at the total cost of $2,306,368 and per-kW cost of was $1,536. The expenditures for this investment are generally consistent to the investment in Deer Lake. The observed cost differences can mostly be attributed to transportation and labour costs. Some of the First Nation communities are less accessible than others due to isolation and lack of year-round roads.

2.4. Benefits

a) Operation Efficiency and Cost Effectiveness

The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option.

b) Customer

This project was initiated by Remotes' customers, who benefit through relief of capacity constraints.

c) Safety

The investment will replace an old generator, which will reduce the probability of an unplanned failure.

d) Cyber-Security, Privacy

All upgrades to generator PLCs and related infrastructure meet the latest cyber-security standards.

e) Co-ordination, Interoperability

As with all generation upgrade projects, Remotes is working closely with the First Nation communities through the funding and approval process. When a community's loading levels begin to approach its rated connection limits, Remotes collaborates with the community to identify possible solutions to alleviate the capacity constraints. If a generator upgrade project is determined required, the customer requests the company to undertake the work, and Remotes works with the community to secure INAC funding for the project. Under the terms of the electrification agreements, INAC is responsible for funding generation capital upgrades associated with load growth in First Nation communities served by Remotes. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

The community of Sandy Lake is anticipating connection to new transmission lines that will reach the community at an undetermined date. The Remote Community Connection Plan is still in its draft form until further community consultations are completed. Since connection constraints are anticipated beginning in 2018, the upgrade project is proposed to proceed.

f) Economic Development

The majority of Remotes customers are First Nations and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment will relieve system capacity constraints in Sandy Lake, which is conducive to economic growth.

g) Environment

The new generator unit will meet the latest standards in emissions and fuel efficiency.

3. Prioritization

This is a non-discretionary project, since it is requested by customers and funded by INAC. The project takes priority over discretionary projects/programs.

4. Execution Path

4.1. Implementation Plan

The project is planned over a three-year period. Design of upgrade will take place in 2018, procurement and installation in 2019, and completion of construction and commissioning in 2020. The work will be done by a dedicated station crew. This project will be coordinated with other work planned in Sandy Lake.

4.2. Risks and Risk Mitigation

The primary concern for this project and other generator upgrades is funding from INAC. In the past, INAC was unable to consistently support projects due to funding constraints in certain years. Absent the funding from INAC, Remotes does not have the means to recover the costs for this project and the project can not proceed until the situation is resolved. To mitigate this risk, Remotes works closely with the communities it serves and INAC to ensure sufficient funds are available and approved to carry out the work.

Another risk to project completion is the ability to transport heavy electrical equipment to the sites, which requires winter road access. To mitigate this risk, the generator is procured in advance to be ready for transportation in short order when the suitable weather conditions materialize. In case of an entire season passing without safe winter road conditions, the project may need to be deferred. Remotes has the option to hire a specialized aircraft to deliver the equipment if the risk of project deferral is greater than the increased transportation cost.

Finally, Remotes has lodgings for only one crew in each community. Therefore, a risk to the completion of the project as planned is the availability of accommodation for crews to perform work on the generating station as part of this project and emergency work that comes up throughout the year. Remotes mitigates this risk through careful project planning and execution. Remotes also can rent temporary accommodation in necessary.

4.3. Timing Factors

Winter road availability and the ability to safely fly in crews are factors that can affect the timing of this investment. This project may be deferred due to transportation or INAC funding delays, which are mitigated through project planning and coordination. Besides these factors, the project is customer-initiated, non-discretionary and externally-funded, and therefore takes priority over discretionary projects/programs.

4.4. Cost Factors

A large part of the final cost of this project will be transportation cost. The inaccessibility of the First Nation communities makes shipping both unreliable and expensive. Another important factor that may affect the final cost of the project is labour cost. Controllable costs are minimized by using experienced station crews and selecting the most cost-effective transportation option.

4.5. Customer Preferences

This project was initiated by Remotes' customers.

4.6.Regional Electricity Infrastructure Requirements

This project does not directly arise from Regional Electricity Infrastructure Requirements. The 2016 Order-in-Council by the Minister of Energy identified 16 communities which will be connected to new transmission lines passing through northern Ontario, including Sandy Lake. The Remote Community Connection Plan is still in its draft form until further community consultation is performed and a federal/provincial funding agreement is in place. The anticipated connection dates of these communities are not known. The peak load in Sandy Lake is forecast to reach the connection limit in 2018; therefore, the project is proposed to move ahead subject to the availability of INAC funding.

4.7.Incorporation of Advanced Technology

N/A

4.8. Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Weagamow DGS Upgrade

1. Project/Program Description

1.1. Current Issue

The peak load in North Caribou First Nation (Weagamow) reached 1096 kW in 2013, which is over ninety percent (90%) the station's connection limit of 1211 kW. An interim station upgrade was performed in 2016 to help address capacity constraints in the short term. However, the peak load is forecast to reach the technical connection limit in 2019, necessitating a larger upgrade to ensure connection capacity availability over the longer term. Accordingly, Remotes' customers have requested funding through INAC to upgrade the generating station capacity in Weagamow.

1.2. Project Scope

Subject to the availability and amount of INAC funding approved, the Weagamow upgrade would replace all four generators comprising the community's current generating station. Weagamow unit A was installed in 1996 and is rated 600 kW. Unit B was upgraded in 2016 from 250 kW to 725 kW capacity. Unit C was installed in 2008 with 400 kW capacity. The 1-MW D unit is owned by the North Caribou First Nation. The three units owned by Remotes are all medium speed (1800 rpm). The unit owned by the North Caribou First Nation is low speed (1200 rpm). The four units would be replaced with four units with an upgraded total station capacity of 2 MW. The existing generators owned by Remotes will be returned to inventory.

The proposed upgrade also includes construction of a larger facility to host the generating equipment, to address the spatial restrictions that characterizing the current facility, which complicate the tasks of generator maintenance and introduce potential safety risks for the company's staff.

1.3. Main and Secondary Drivers

As per Table 1-1 in the DSP, the key driver for the proposed generator upgrade investments is addressing System Capacity constraints (i.e. expected changes in load that will constrain the ability of the system to provide requisite output under peak conditions). Weagamow's peak load is forecast to exceed the station's connection limit in 2019, necessitating the upgrade work.

The condition of the station and reliability concerns are the secondary drivers for the upgrade. The existing building is too small to house all the generators creating restricted workspaces when engine repair or maintenance is required. Meanwhile, the condition of the D unit places reliability within the community at risk since the unit has experienced several prolonged outages in the past and is operated by the North Caribou Lake First Nations on a run-to-failure basis.

1.4. Performance Targets and Objectives

Remotes manages its diesel generating station by limiting the peak load at the station 85% of the station's rating. This threshold allows for consumption growth as existing customers connect more devices to the grid without compromising the ability to supply power during peak load. The proposed generator upgrade at Weagamow would relieve the system constraints.

The investment would also affect several performance targets listed in Remotes' DSP. The upgrade of the generator would reduce the probability of its unplanned failure, thereby improving reliability and generator availability. Based on Remotes' customer engagement efforts described in Section 2.3.1.1 of the DSP, reliability is a key driver for customer satisfaction. By replacing old generators with new ones that meet the latest energy efficiency standards, both diesel generation efficiency and carbon emission intensity would be improved. New generators are approximately 10% more efficient than in-service units.

1.5. Customer Impact

a) Customer profile for the community:

Customer Class	Non Std A – Res.	Non Std A – Seas.	Non Std A – GS 1P	Non Std A – GS 3P	Street Lightning	Std A – Res. – Air	Std A – GS – Air	Total
Community	**Number of Customers**							
Weagamow	244	-	24	1	1	12	26	308

b) Customer impacts for the community:

The table below presents the customer impacts for North Caribou Lake (Weagamow). The value of customer impact is defined as follows:

- High – less than 10% seasonal customers.
- Medium – between 10% and 50% seasonal customers.
- Low – greater than 50% seasonal customers

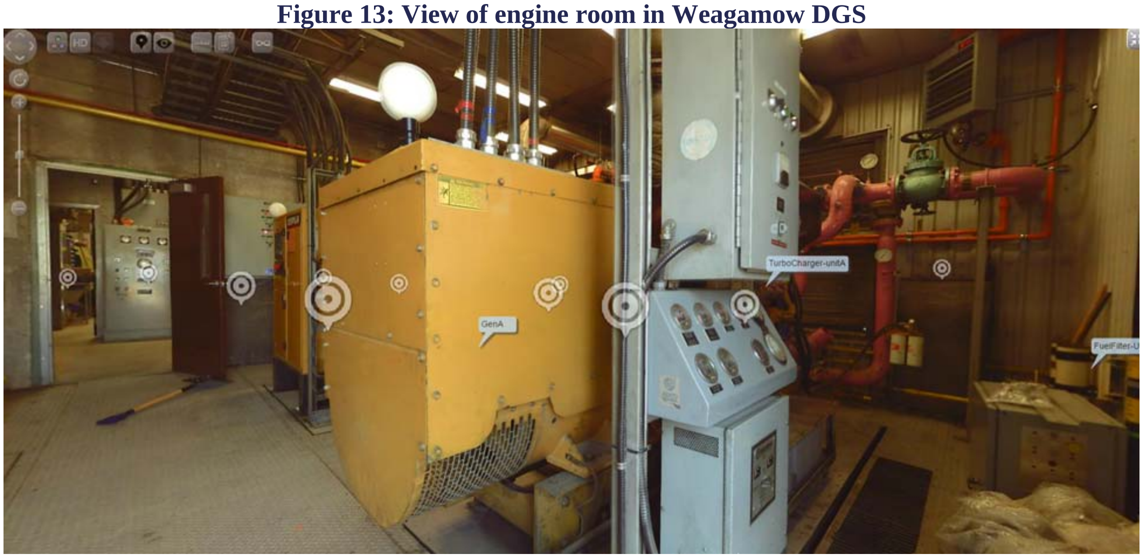
Community	Customer Count	Load at Risk (kW peak)	Value of Customer Impact
Weagamow	308	1096	High

1.6. Supporting Documentation

Figures 1 and 2 depict the generator rooms in Weagamow DGS. As can be seen from the pictures, the facility's size relative to the size and configuration of the generator equipment it hosts, results in significant spatial restrictions that complicate the task of servicing the equipment. The 725-kW B unit was put into service in 2013 in response to reliability concerns of the D unit and the First Nation would not permit expansion of the existing site, resulting in the present-day constraints.

Figure 12: Close-up of engine in Weagamow DGS

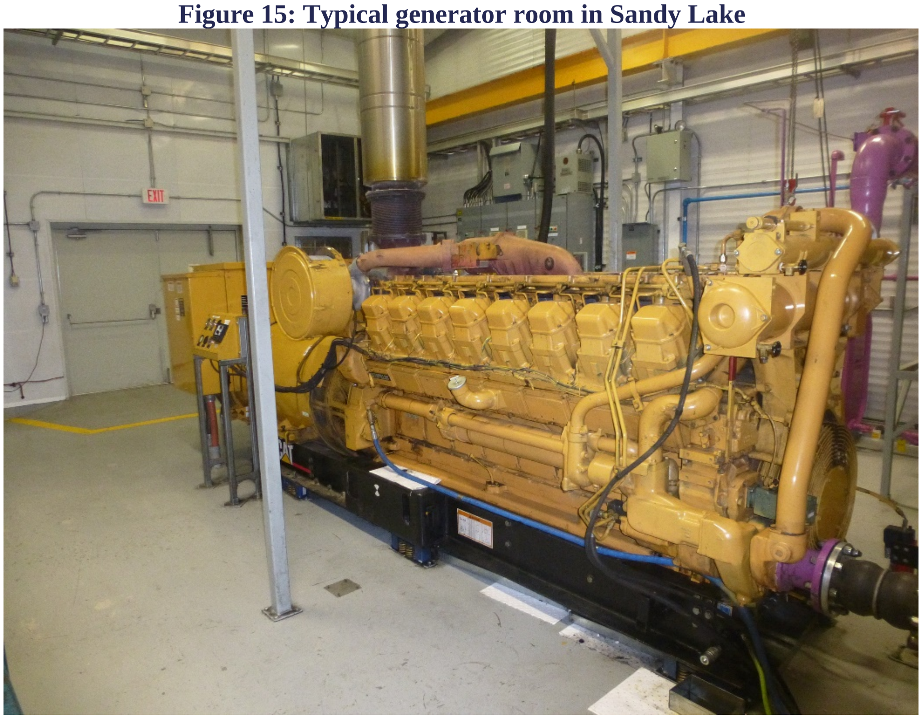
Figure 13: View of engine room in Weagamow DGS



For comparison, Figures 3 and 4 depict the generator rooms in Deer Lake and Sandy Lake, which are of standard sizes and each contain just one (1) engine, providing sufficient space for servicing the equipment.

Figure 14: Typical generator room in Deer Lake

Figure 15: Typical generator room in Sandy Lake



2. Project/Program Justification

2.1. Information Used to Justify the Investment

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load surpasses 85% of the station rating. Since Weagamow's load is anticipated to reach the connection limit in 2019, the station upgrade is being proposed to avoid any connection restrictions. The forecast peak load in Weagamow for the years 2017 through 2022 is shown below. This forecast is based on historical data that has determined the future annual load increase in Weagamow to be around three per cent. Beyond the community's internal growth projections, the magnitude of the forecast load growth is also a function of a planned completion of an all-season road to the community in 2017.

Community	Connection Limit (kW)	Peak Load Forecast (kW)					
		2017	2018	2019	2020	2021	2022
Weagamow	1105	1062	1094	1127	1160	1195	1231

The spatial restrictions and condition of the station facility itself are also significant drivers for the project. The existing building is too small to house all the generators. In stations where engines are larger than 200 kW, each engine is normally located in a separate room so that work can be done without the risk of permanent hearing damage to operators. In Weagamow, the 600-kW and 400-kW units are housed in the same room (see Figure 2) creating significant spatial restrictions that affect the manner in which work has to be performed (by extension, affecting execution efficiency and employee safety). Presently, spare engine parts must be moved to a temporary location to enable work. Moreover, the 600-kW unit is old and cannot be replaced if it were to fail, since new 600-kW units are too large to fit into the existing room in the station. Furthermore, the station has a wood floor, presenting an unacceptable environmental risk in the event of a fuel spill.

The D unit is stored in a trailer on the property that has reached end-of-life and is too small for maintenance on the unit to be conducted safely. The D unit is operated by Remotes and integrated into the supply needs of the community, but maintenance is paid for under an agreement with the unit's owner – the North Caribou First Nation. Under the terms of the agreement, maintenance by Remotes on the D unit is limited to oil changes and visual inspections. Consequently, the D unit's condition is not maintained with the same rigour as assets subject to Remotes' regular asset management process.

The condition of the D unit puts reliability in the community at risk as the unit is run to failure. For example, in September 2012, the D unit failed. While INAC and the First Nation worked to replace the D unit with a temporary unit, electricity was supplied by the 600-kW engine, along with one of the smaller engines. In November of that year, rotating blackouts were required due to failures of both smaller engines. Both smaller units were returned to service in late December. In January 2013, the 600-kW unit, which had been operating throughout the previous year's emergency conditions, failed. Rotating blackouts were avoided due to the community's conservation efforts while the 600-kW unit was out of service and being repaired. The community secured a 725-kW unit which was put into service in January 2013 until the equipment supplier could complete a major overhaul on the D unit. The temporary 725-kW unit was put into service as the B unit in 2016. Once the D unit is replaced, it will be owned and operated by Remotes and will be maintained as a normal part of Remotes' business. INAC has not yet approved funding for the project.

2.2. Alternatives Evaluation

Alternative 1: Do nothing

The “do nothing” option entails the case where no upgrade is made at the station.

a) Comparison of Project Alternatives

In the case of the “do nothing” option, Remotes would have to defer addressing the request of its customers for this project to proceed, which is contrary to Remotes’ values, and would create connection capacity restrictions within the next three years. This is not the preferred option.

The proposed facility rebuilds and generator replacement project is the preferred alternative. Generally, upgrades are required as community demand increases to ensure Remotes has enough capacity to reliably meet the needs of its customers.

b) Comparison of Technically-Feasible Alternatives

The preferred alternative is to design and build a modular station building that would house four generators. The modular units would be constructed off site. A larger modular unit assembled off site and transported to the community would house each of the units into a larger station. The existing 725-kW generating units will be repurposed, but the existing 600-V alternator will be replaced with a 4160-V alternator. Three new 4160-V generating units will be procured, including two units rated 1500 kW each and one unit other rated 725 kW. As station capacity increases, the size of the 600-V switchgear and cabling becomes too large to accommodate. The 4160-V switchgear bus and cabling is much smaller. The community is expected to be connected to an all-season road by the fall of 2017; therefore, additional on-site fuel storage is not required or requested as part of this project.

Given the uncertainty of INAC funding, Remotes must consider alternatives to downscale the project while addressing the key drivers. Accordingly, Remotes has considered a partial upgrade, including a new standalone trailer to house the First Nation-owned generator if the desired level of funding is not available. The priority will be to replace the First Nations’ unit first, based on its condition, followed by the 600-kW unit, and then the 400-kW unit.

Remotes also considered a more conventional station building upgrade, where the First Nation manages the project and the station construction work is contracted out to a third party. Conventional upgrades, wherein most of the construction is completed on site, are costlier than using modular units. As the community is planning an all-season road that is expected to be in place by the fall of 2017, a modular design with completed manufacturing off-site is possible, less costly, and more time efficient. As such, it is a practical alternative given that INAC has limited funds.

The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

2.3.Project/Program Timing and Expenditure

a) Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017*	2018	2019	2020	2021	2022
Capital (Gross)	-	-	14	1,816	1,485	2,832	1,993	-	-	-
Contributions	-	-	(13)	(1,634)	(1,336)	(2,549)	(1,794)	-	-	-
Removals	-	-	(1)	(182)	(149)	(283)	(199)	-	-	-
Net Capital	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-

b) Start Date

Procurement in 2018
Construction in 2019

c) In-Service Date

Fall 2019

d) 2018 Test Year Expenditure Timing

	Forecast Costs ($ '000)			
	Q1	Q2	Q3	Q4
Capital (Gross)	708	708	708	708
O&M	-	-	-	-

e) Comparative Expenditure Information

The plant in Webequie, which includes three generators and a combined station capacity of one MW, was built by a third-party contractor in 2008, at an estimated cost of approximately $16M. The proposal in Weagamow is to design and build a modular 2-MW plant at a cost of under $10M.

2.4. Benefits

a) Operation Efficiency and Cost Effectiveness

The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes, which is usually the most cost-effective option. The proposed modular design is more cost-effective than a traditional substation rebuild. The existing generators will be returned to inventory.

b) Customer

This project was initiated by Remotes' customers. The project simultaneously addresses forecast connection constraints in the community and historical reliability concerns of the D unit. Customers benefit from improved electricity availability.

c) Safety

Alleviating the spatial restrictions of the generator building would enable Remotes staff to conduct regular wok activities in a safer manner.

d) Cyber-Security, Privacy

In accordance with the NIST Guide to Industrial Control Systems Security, the planned upgrade includes restrictions of physical access to the station, PLC monitoring to detect security events, a demilitarized zone ("**DMZ**") network architecture, and restrictions of unauthorized remote access.

e) Co-ordination, Interoperability

As with all generation upgrade projects, Remotes is working closely with the First Nation communities through the funding and approval process. When a community's load begins to approach its connection limit, Remotes collaborates with the community to identify possible solutions to alleviate the capacity constraints. If a generator upgrade project is determined to be required, the customer formally requests Remotes to undertake the project, and Remotes works with the community to secure INAC funding for the project. Under the terms of the electrification agreements, INAC is responsible for funding generation capital upgrades associated with load growth in First Nation communities served by Remotes. The communities have the final say in the technical design of the project based on the feasible options outlined by Remotes.

The community of Weagamow is anticipating connection to new transmission lines that will reach the community at an undetermined date. The Remote Community Connection Plan is still in its draft form until further community consultations are completed. The likely timeline for grid connection is between 2027 and 2037. Since connection constraints are anticipated beginning in 2018, the upgrade project will proceed.

f) Economic Development

Most of Remotes' customers are First Nations, and many of their suppliers and contractors are First Nation enterprises. Remotes frequently hires local station operators and provides extensive training. This investment will relieve system capacity constraints in Weagamow, which is conducive to economic growth.

g) Environment

The new generator unit will meet the latest standards in emissions and fuel efficiency.

3. Prioritization

This is a non-discretionary project, since it is requested by customers and funded by INAC. The project takes priority over discretionary projects/programs.

4. Execution Path

4.1. Implementation Plan

Procurement of generators, building, and transportation of generators to Weagamow is planned to take place in 2018. Assembly of the building modules and installation of the generators would then be completed in 2019. The work will be done by a dedicated station crew. This project will be coordinated with other work planned in Weagamow, including a civil plant improvement (a separate project) in 2018.

4.2. Risks and Risk Mitigation

The primary risk factor for this project and other generator upgrades is funding from INAC, the levels of which have fluctuated in the past, depending on considerations outside of Remote's control. Absent the funding from INAC, Remotes does not have the means to recover the costs for this project and the project would not proceed. To mitigate this risk, Remotes works closely with the communities it serves and with INAC to ensure sufficient funds are available and approved to carry out the work. Based on the approved funding levels, the scope of work may change. The proposed modular station design is the optimal investment plan, but a partial rebuild can be completed to meet the supply needs of the community with limited funding.

Another risk to project completion is the ability to transport heavy electrical equipment to the sites, which requires the completion of an all-season road. Remotes expects the all-season road to this community to be completed in 2017. If this is not the case, then the costs and timing of the project will change.

Remotes has lodgings for only one crew in each community. Therefore, a risk to the completion of the project as planned is the availability of accommodation for crews to perform work on the generating station as part of this project, relative to emergency work that comes up throughout the year. Remotes mitigates this risk through careful project planning and execution. Remotes also can rent temporary accommodation if necessary.

4.3. Timing Factors

If the completion of an all-season road to the community is delayed, then the construction of a modular station would be delayed. This project may be deferred due to transportation or INAC funding delays, which are mitigated through project planning and coordination. Besides these factors, the project is customer-initiated and externally-funded and, therefore, takes priority over discretionary projects/programs.

4.4. Cost Factors

A large part of the final cost of this project will be transportation cost. The remoteness of the First Nation communities makes crew transportation expensive. Another important factor that may affect the final cost of the project is labour cost. Controllable costs are minimized by using experienced station crews and selecting the most cost-effective transportation option.

4.5. Customer Preferences

This project was initiated by Remotes' customers, the North Caribou Lake First Nation, who will have the final say in the technical design of the project.

4.6.Regional Electricity Infrastructure Requirements

This project does not directly arise from Regional Electricity Infrastructure Requirements. The 2016 Order-in-Council by the Minister of Energy identified 16 communities which will be connected to new transmission lines passing through northern Ontario, including North Caribou Lake

(Weagamow). The Remote Community Connection Plan is still in its draft form until further community consultation is performed and the anticipated connection dates of these communities are not known. The peak load in Weagamow is forecast to reach the connection limit in 2019; therefore, the project will proceed. The project plan accounts for the anticipated future connection in this community and tank storage upgrades have been foregone as a more near-term approach due to the long-term uncertainties.

4.7. Incorporation of Advanced Technology

N/A

4.8. Leave to Construct Approval

N/A

5. REG Investment Costs

N/A

Appendix B: North of Dryden IRRP

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.

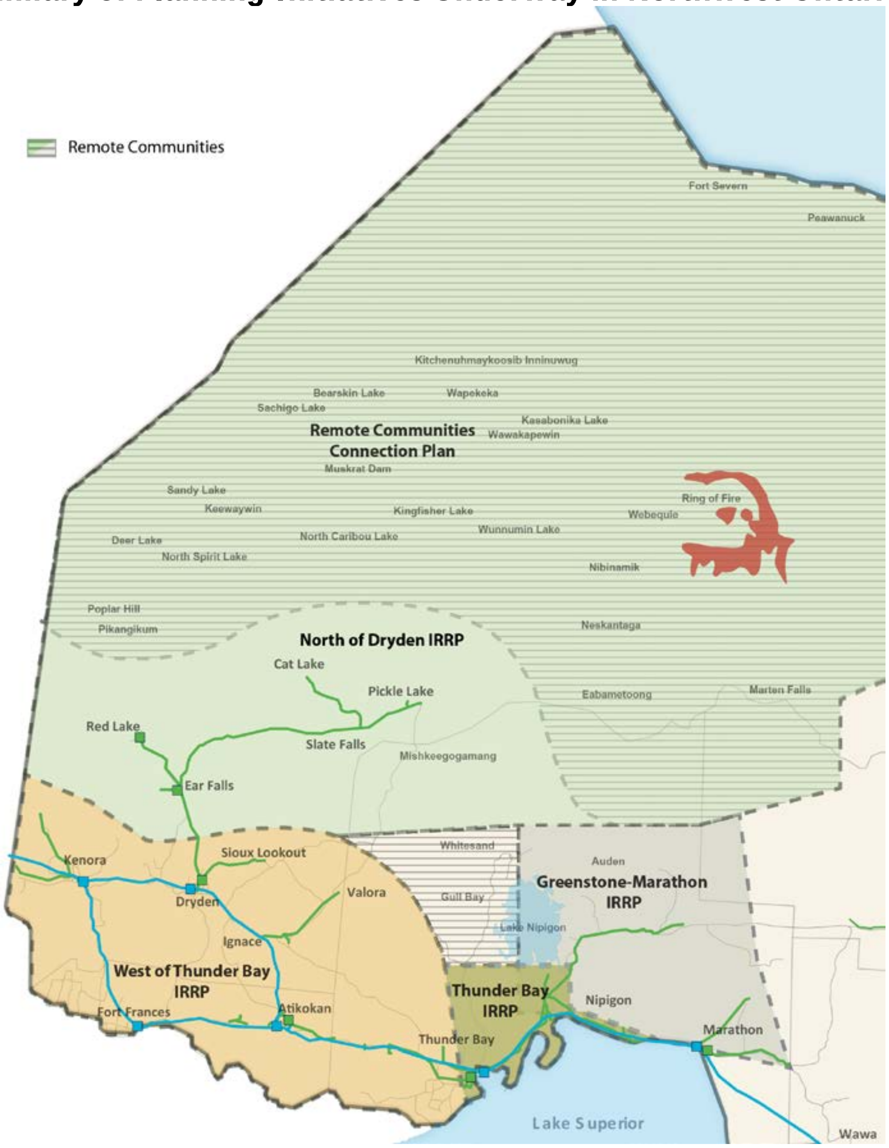
1 EXECUTIVE SUMMARY

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

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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.

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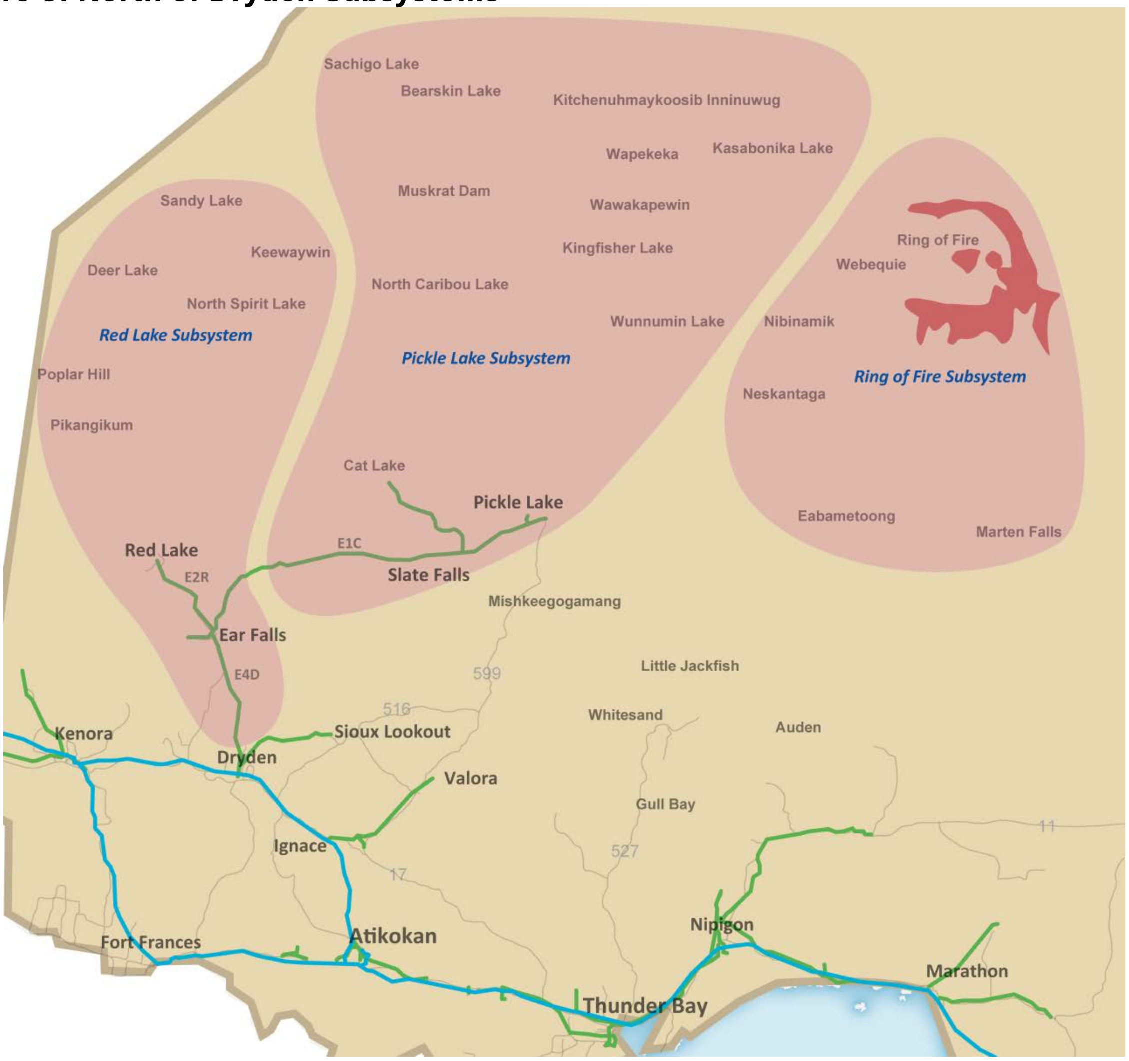
[1] A report entitled "Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario" was developed by the Northwest Ontario First Nations Transmission Planning Committee and the OPA. The document can be found at this website: http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.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.

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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

<table>
<tr><th>Implementation Timing</th><th>Pickle Lake Subsystem</th><th>Red Lake Subsystem</th><th>Ring of Fire Subsystem</th></tr>
<tr><td colspan="4">Conservation and DG Options</td></tr>
<tr><td>Near term and medium to long term (2014-2033)</td><td colspan="3">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.</td></tr>
<tr><td colspan="4">Transmission Options</td></tr>
<tr><td>Near term (2014-2018)</td><td rowspan="2">Build a new 115 kV
OR
230 kV transmission line from the Dryden/Ignace area to Pickle Lake
Cost: $80 M - $114 M</td><td>Upgrade existing transmission lines serving Red Lake (E4D and E2R)
Cost: $11 M</td><td rowspan="2">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</td></tr>
<tr><td>Medium to long term (2019-2033)</td><td>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]</td></tr>
<tr><td colspan="4">Generation Options</td></tr>
<tr><td>Near term (2014-2018)</td><td rowspan="2">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</td><td>Gas fired generator utilizing up to 30 MW of available gas pipeline capacity at Red Lake
Cost: $51 M</td><td rowspan="2">On-site generation fuelled by compressed natural gas or diesel,
Cost: $209 M - $946 M[4]
Separately connect remote communities</td></tr>
<tr><td>Medium to long term (2019-2033)</td><td>Gas-fired generator utilizing up to 30 MW of available gas pipeline</td></tr>
</table>

[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

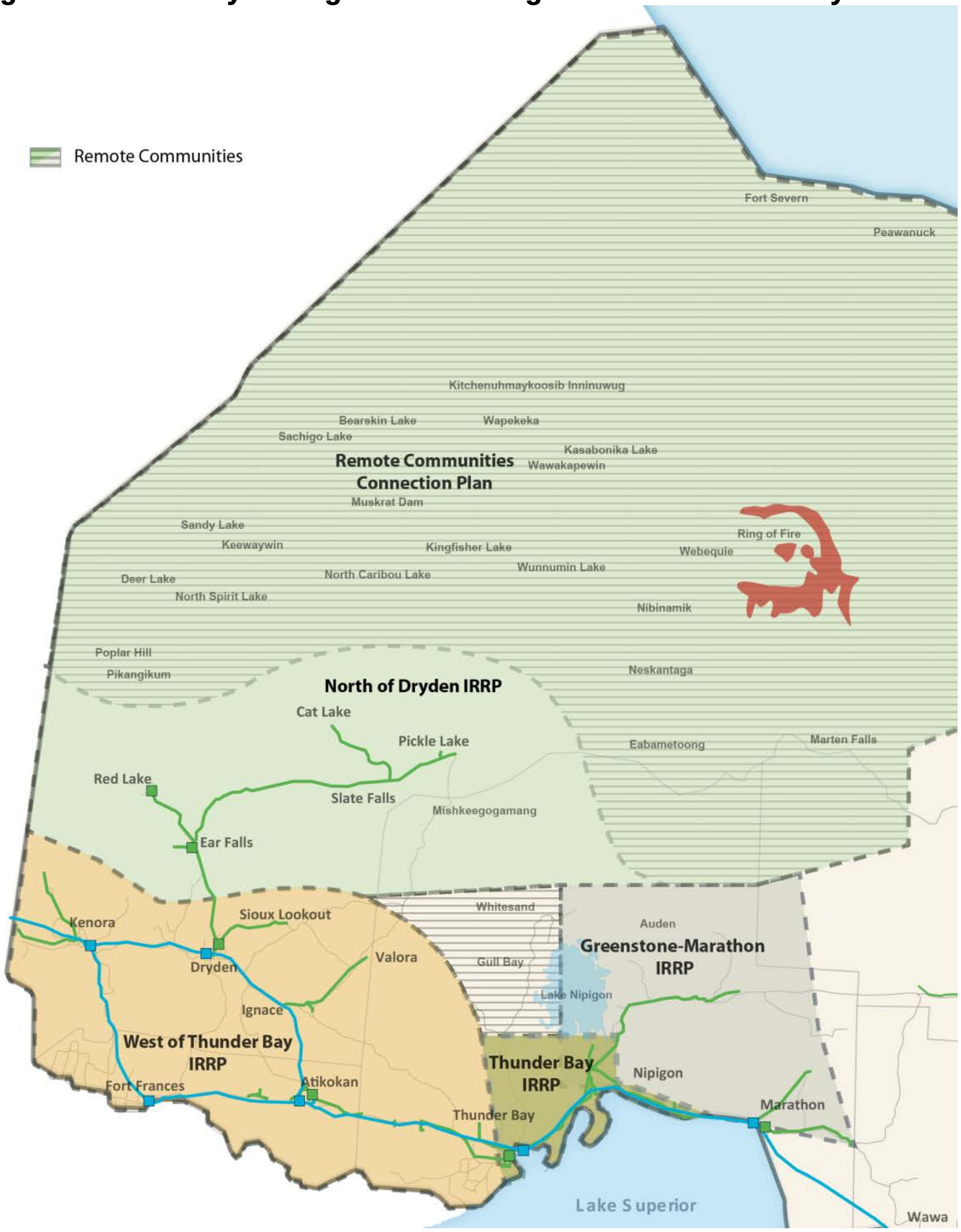
2.1 The North of Dryden Sub-Region

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”).

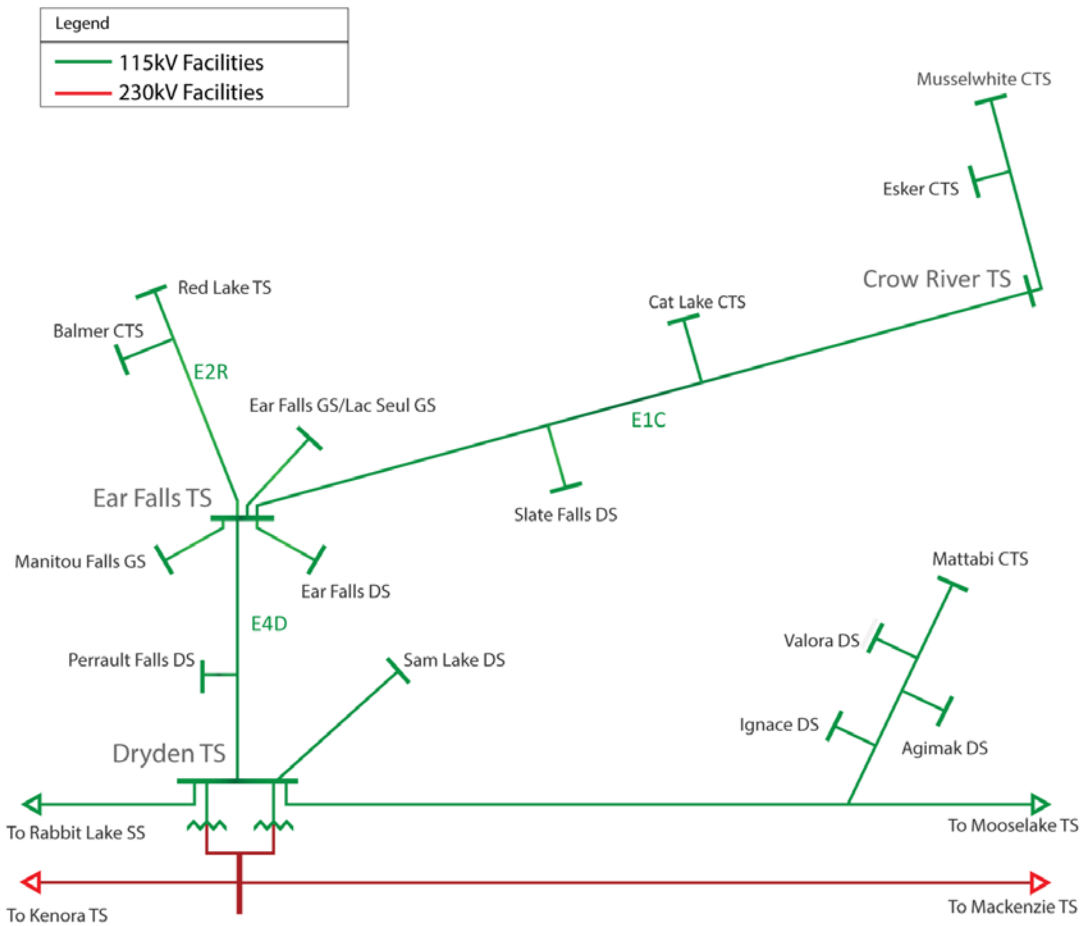
Other planning activities for the region will consider supply needs to the Dryden area for supply of expected load growth in the North of Dryden sub-region. Some of the planning and development work that is underway to ensure an adequate supply is available in the overall Northwest region includes development 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



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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

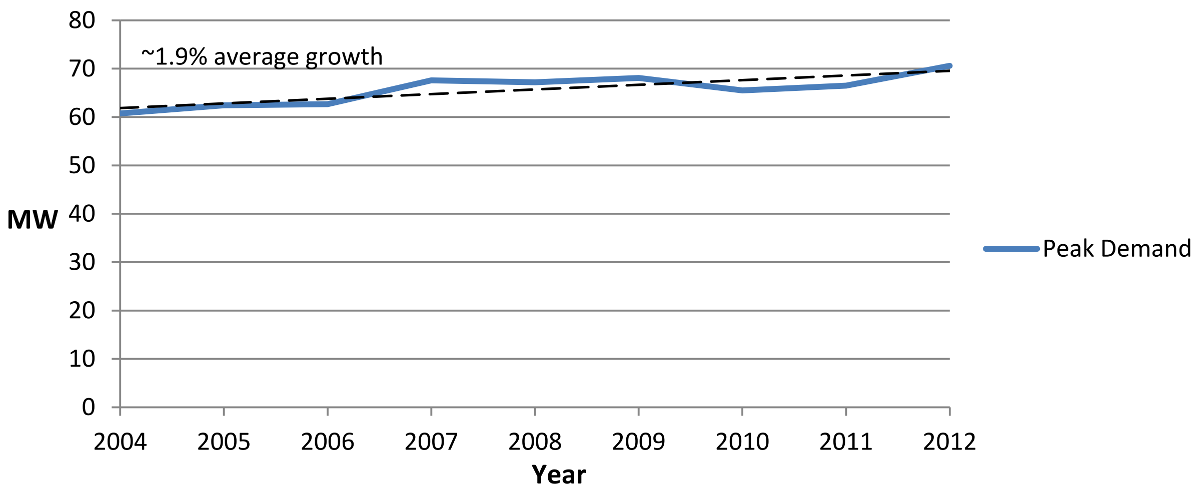
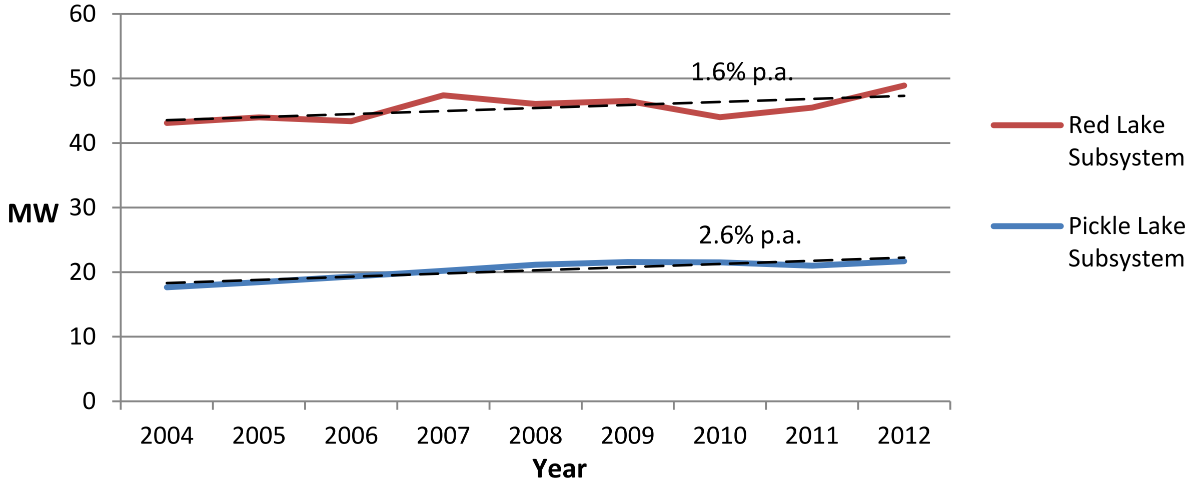


Figure 9 shows that growth in electricity demand has also varied between the Red Lake and Pickle Lake subsystems, with annual growth in electricity demand averaging 1.6% in the Red Lake subsystem and 2.6% in the Pickle Lake subsystem between 2004 and 2012.

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.

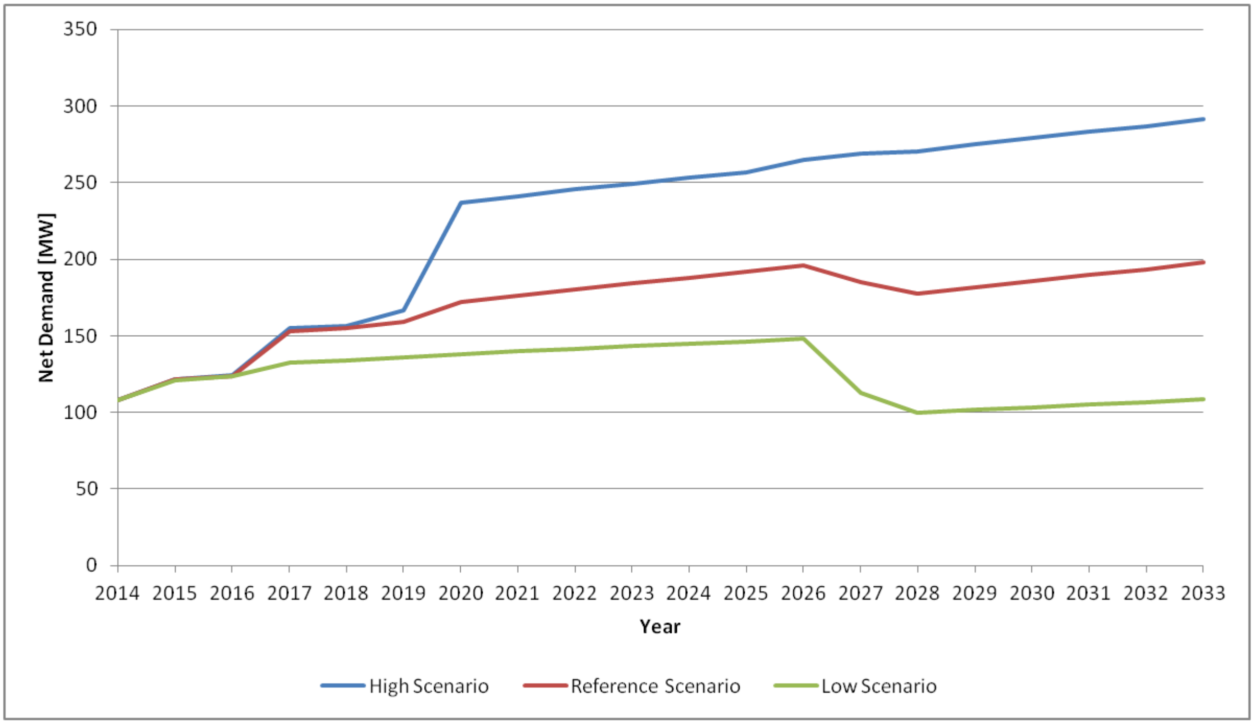
Numerous projects have been proposed in the region, representing a variety of mineral resources, stages of feasibility and development and potential environmental impacts. As mining is a commodity-based industry, there is uncertainty with the timing of mining projects, especially those that are in the 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

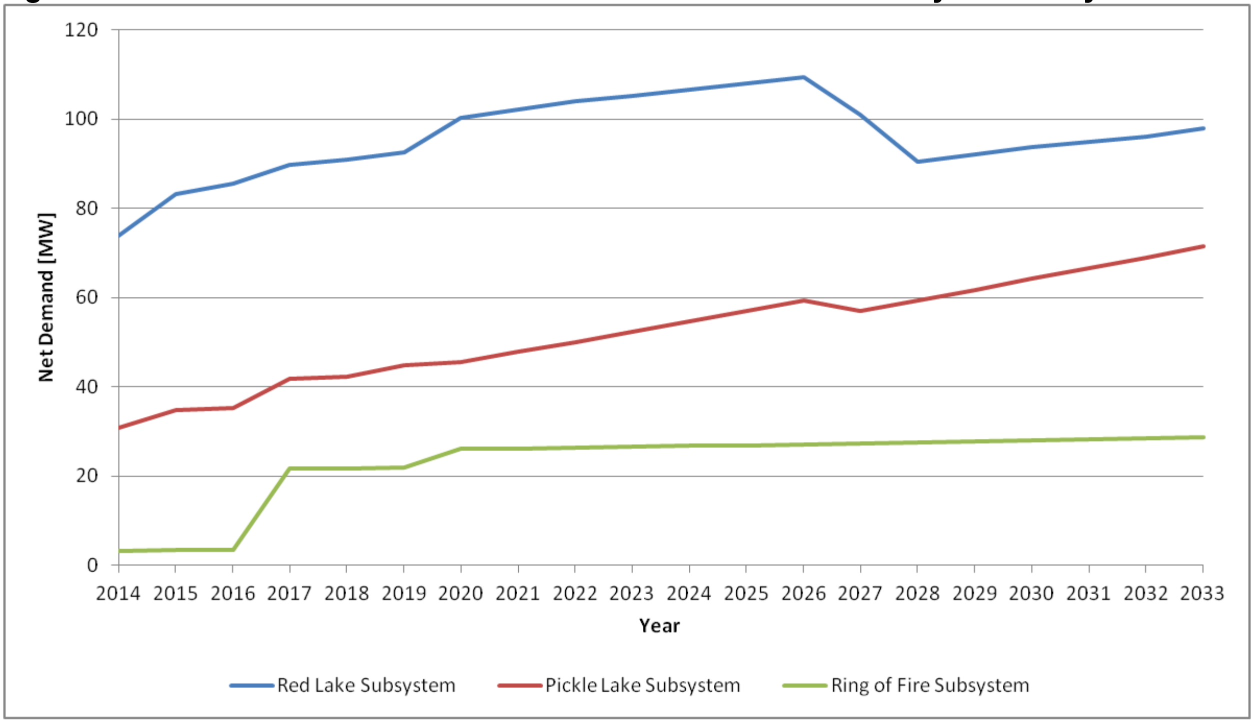


The following descriptions provide the scope of regional activity under the three scenarios.

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.

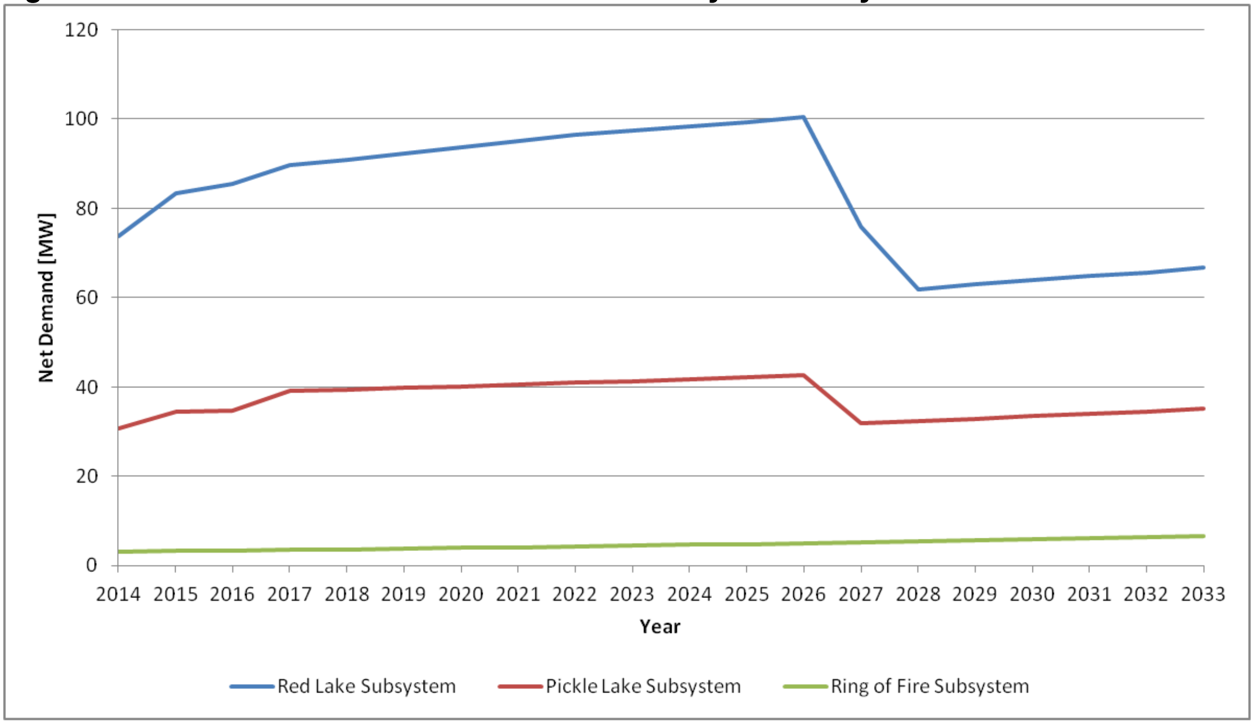
Figure 11: Reference Scenario Demand Forecast for North of Dryden Subsystems



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.

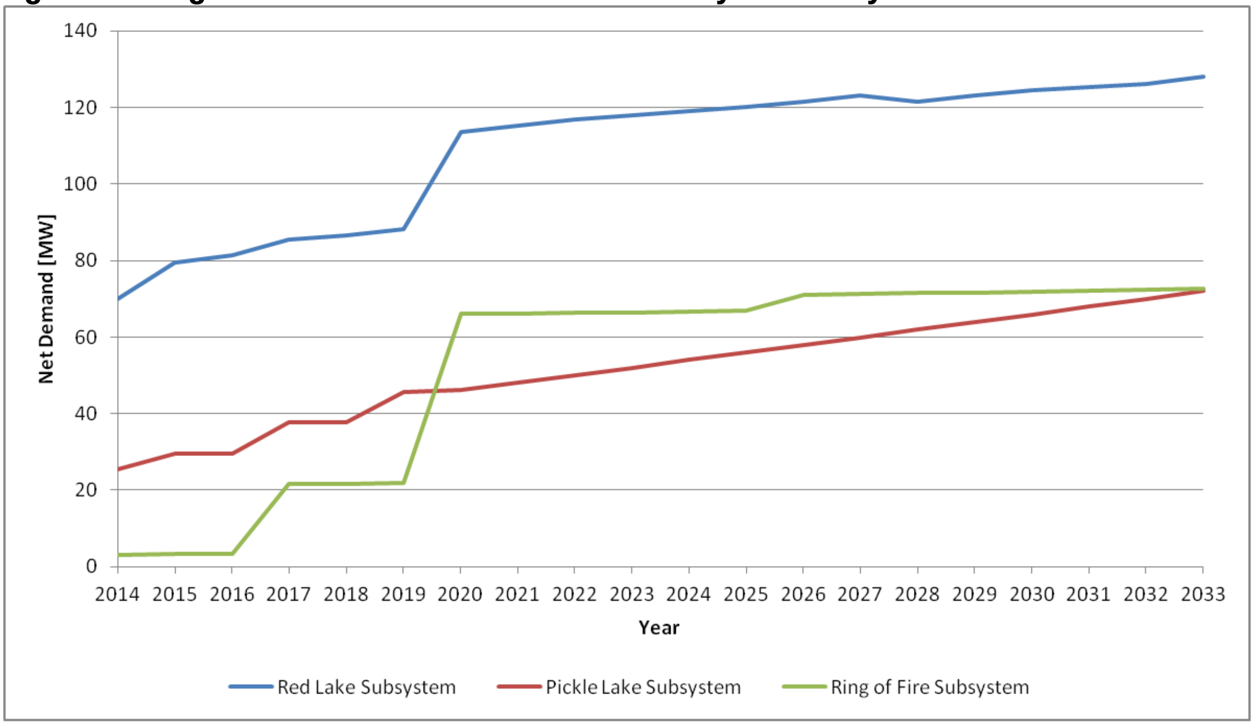
Figure 12: Low Demand Forecast for North of Dryden Subsystems



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

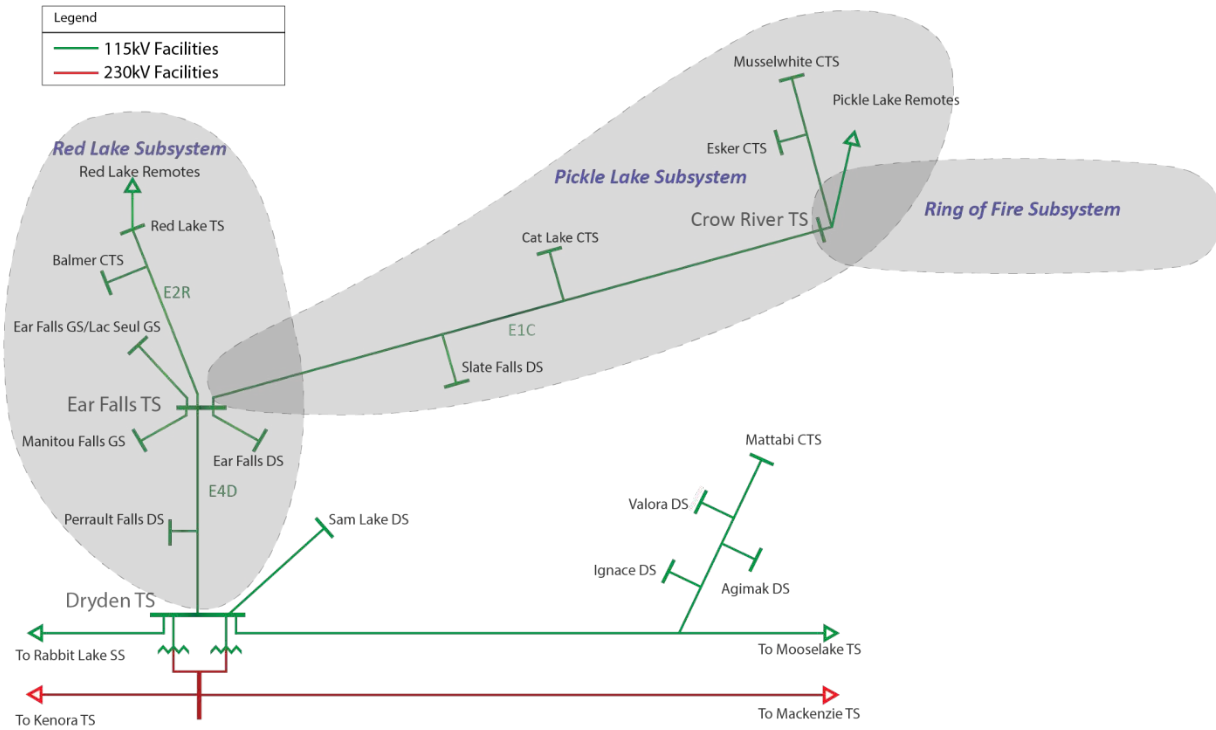
[20] Includes LMC required to supply remote communities that are economic to connect.

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



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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.

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[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

[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.

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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

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Reference Forecast Demand [MW]	Medium and Long term Reference Forecast Demand [MW]
Red Lake Gas Generation (30 MW)	30 MW	91 MW	91	109
and Transfer of Pickle Lake load to new line to Pickle Lake	35 MW	126 MW		

Table 30: 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	$1.94 M/MW
Transfer of E1C load to new line to Pickle Lake[59]	3-5 Years	$66 M	$42 M	

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

<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 colspan="5">Near-term Option</td></tr>
<tr><td rowspan="2">Upgrade E4D and E2R
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>34</td><td>95</td><td rowspan="2">91</td><td rowspan="2">109</td></tr>
<tr><td>35</td><td>130</td></tr>
</table>

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

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term Low Forecast Demand [MW]</th><th>Medium and Long term Low 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">100</td></tr>
<tr><td>35 MW</td><td>126 MW</td></tr>
</table>

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 and Transfer of Pickle Lake load to new line to Pickle Lake	34	95	91	136
	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 8^{th}, 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 Northwest Ontario

10.2 List of Terms and Acronyms

10.3 Planning Methodologies

10.4 Technical Studies and Analysis Methodologies

10.5 Existing System Description and It's Load Meeting Capability

10.6 Analysis of Recommended Options

10.7 Generation Options

10.8 Transmission Options

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

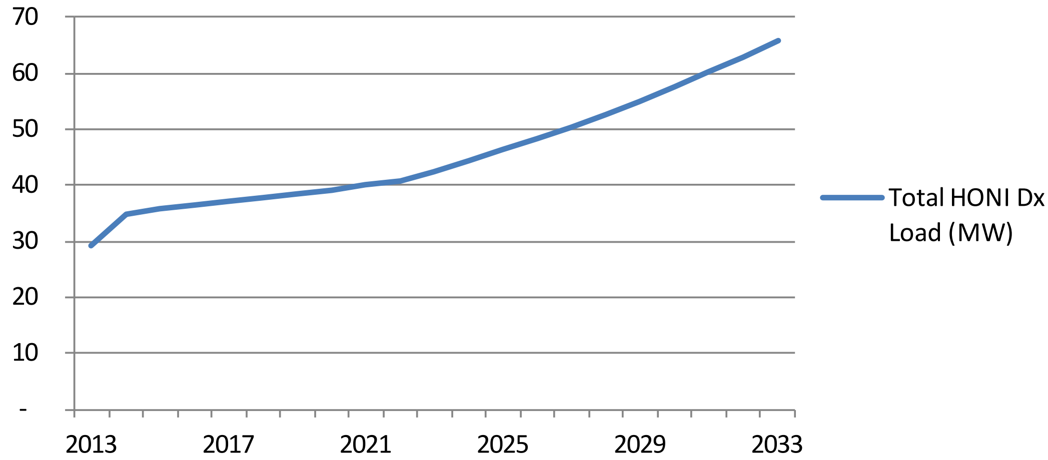
10.3.1 Hydro One Distribution - Reference Demand Forecast Methodology

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.

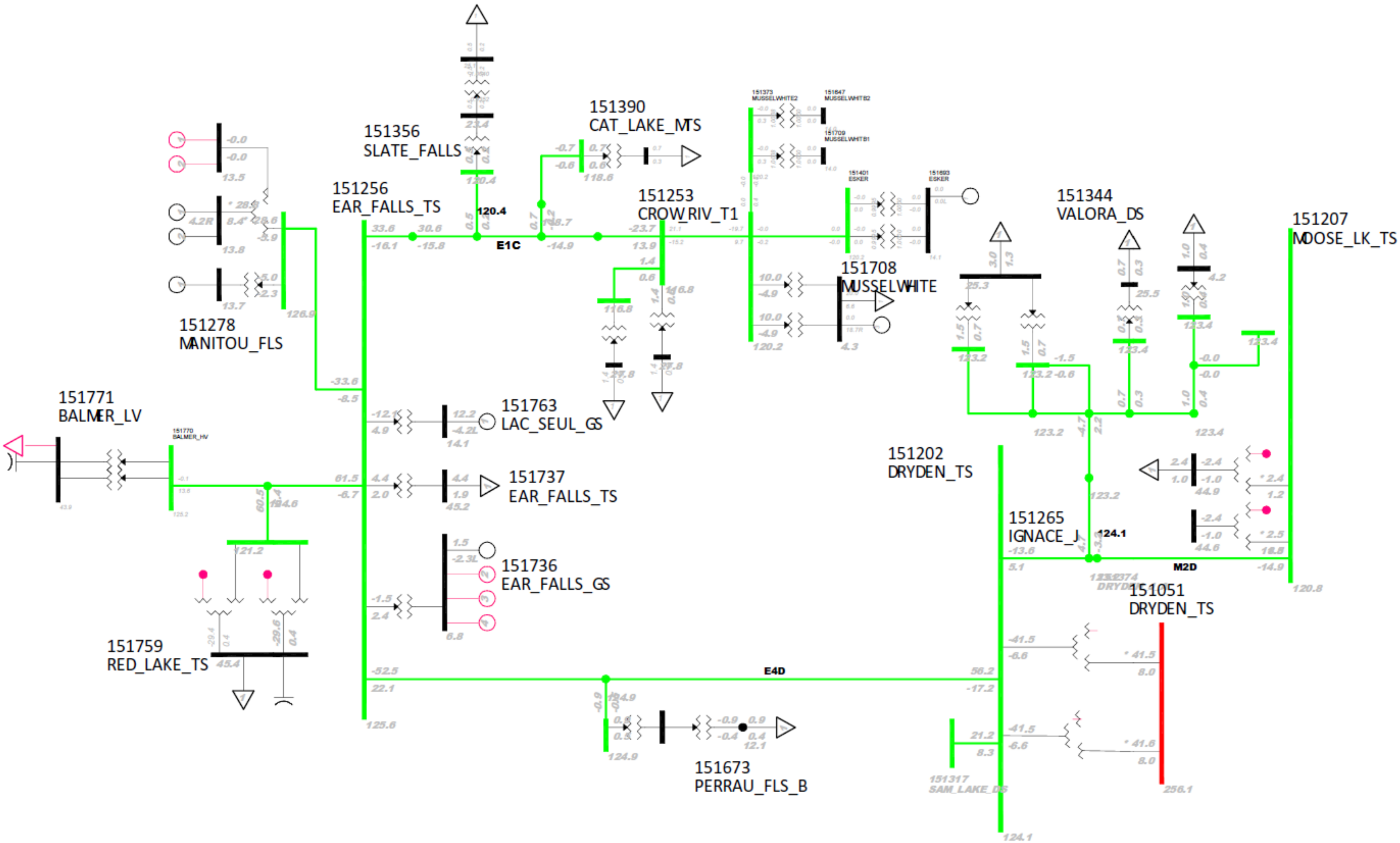
Local Area Assumptions

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



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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.

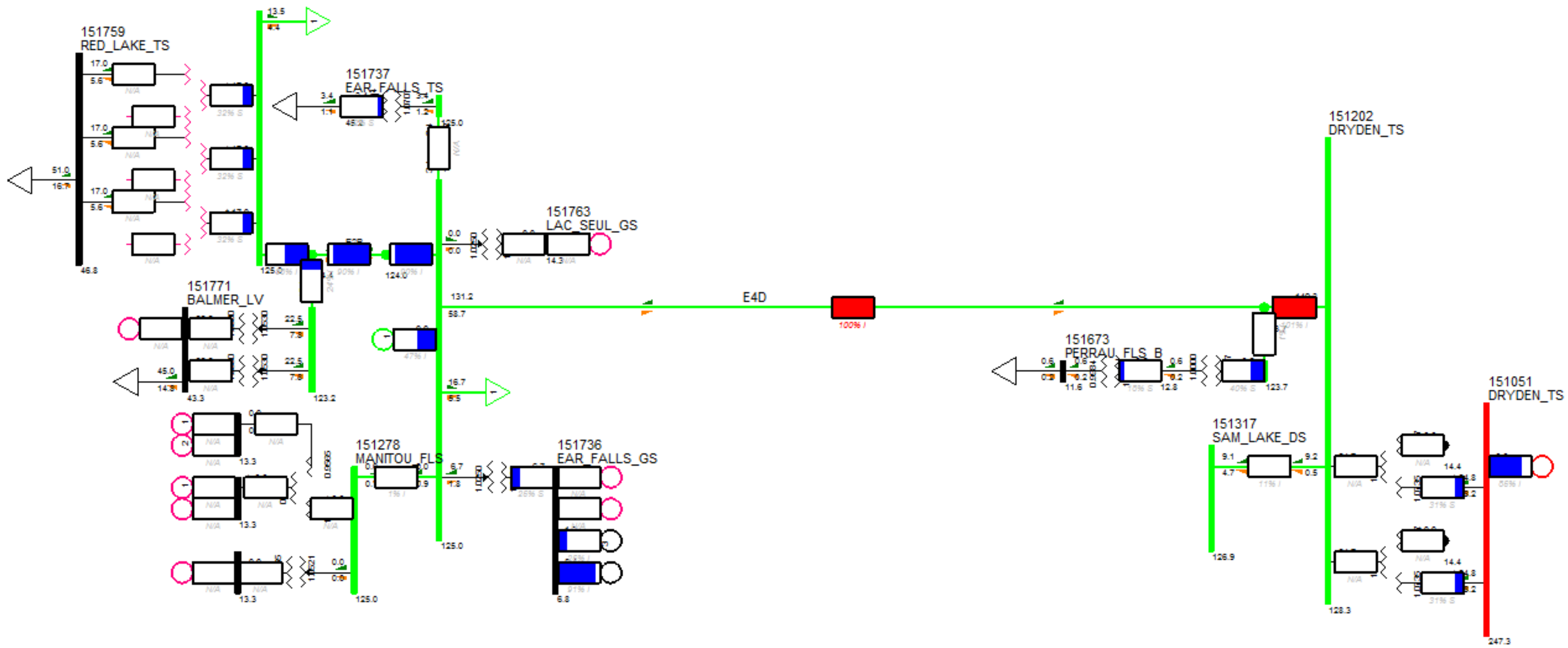
3. Where there was existing thermal capacity on transmission equipment, load was increased and new voltage control requirements were established, to determine the LMC. Load was increased at a central system bus within the subsystem (Pickle Lake area TS for the Pickle Lake subsystem, Ear Falls TS for 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



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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

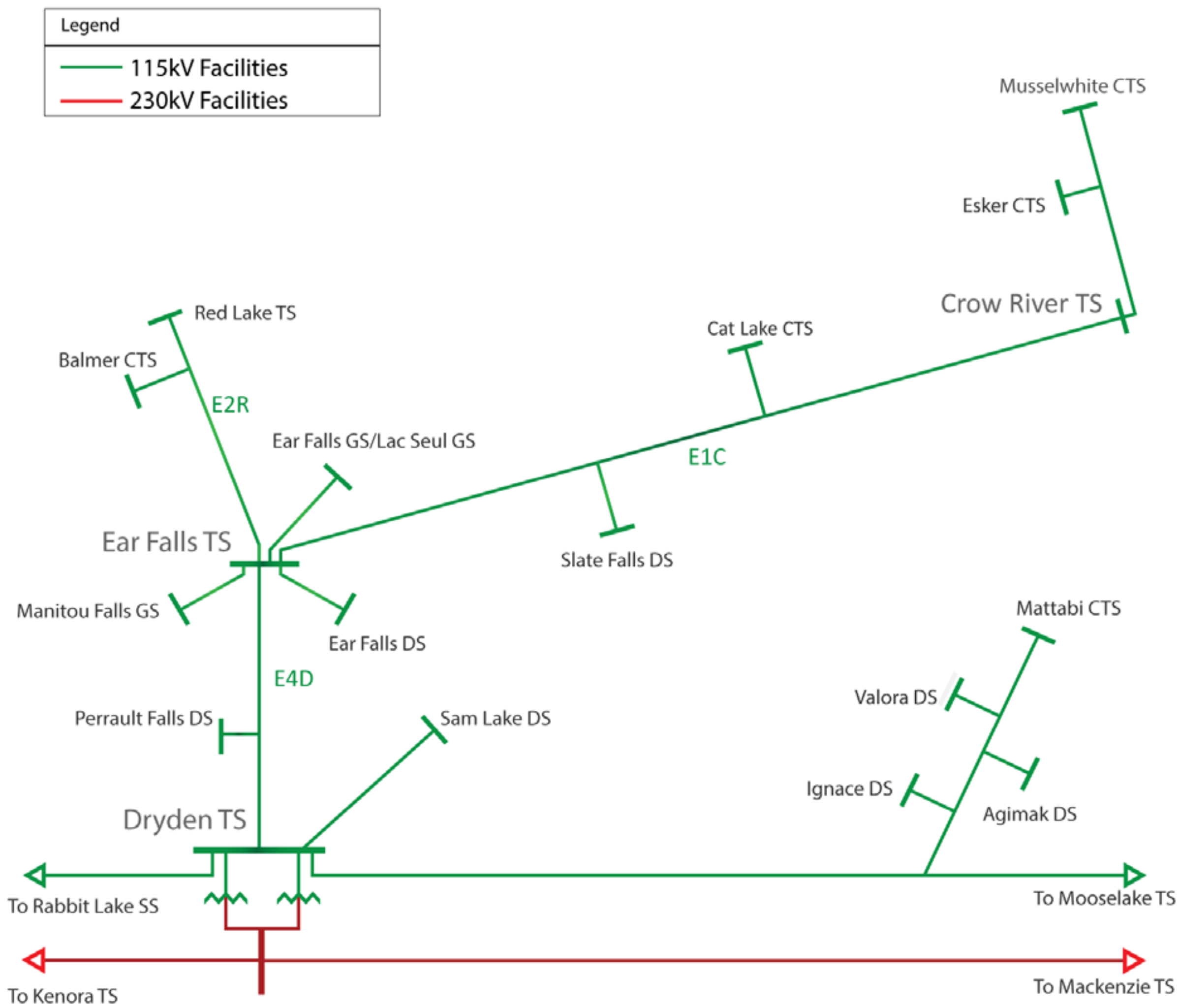
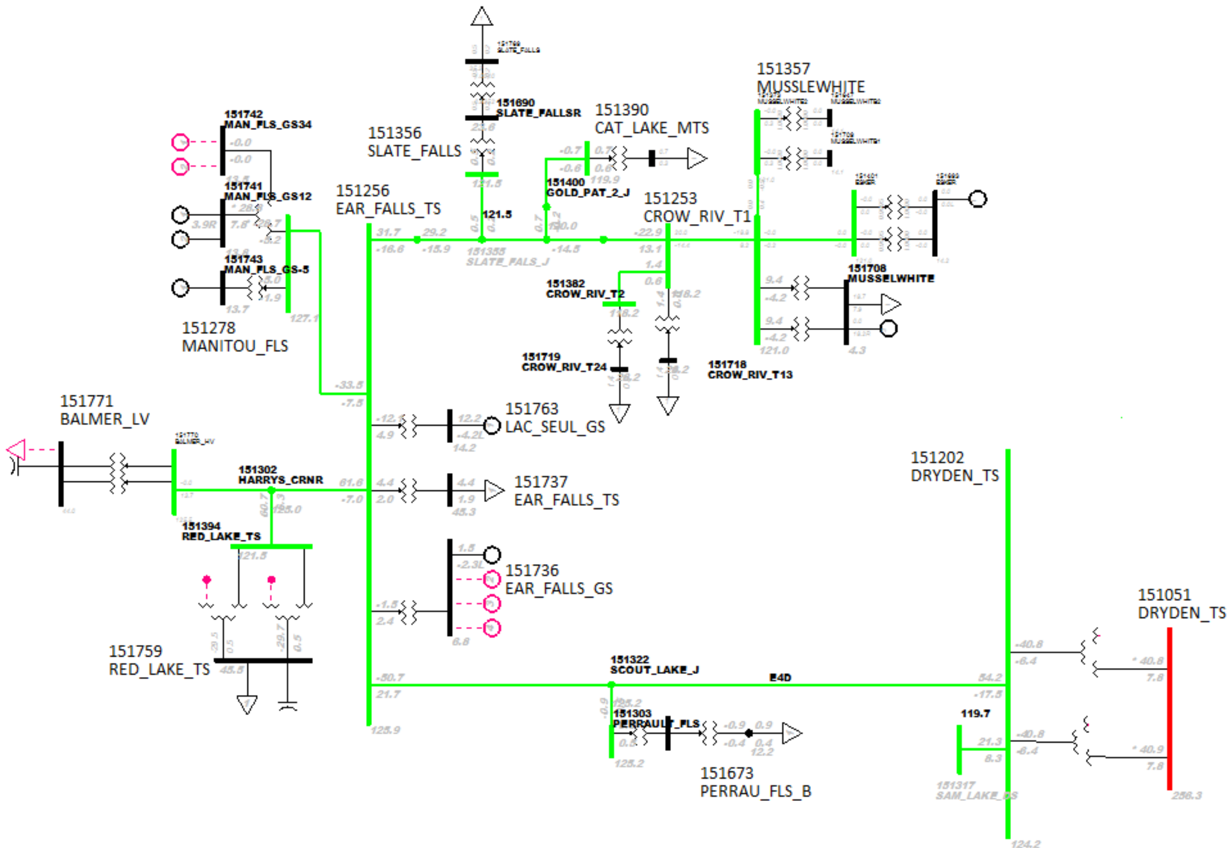


Figure 19: Existing North of Dryden Transmission System Load Flow Plot



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

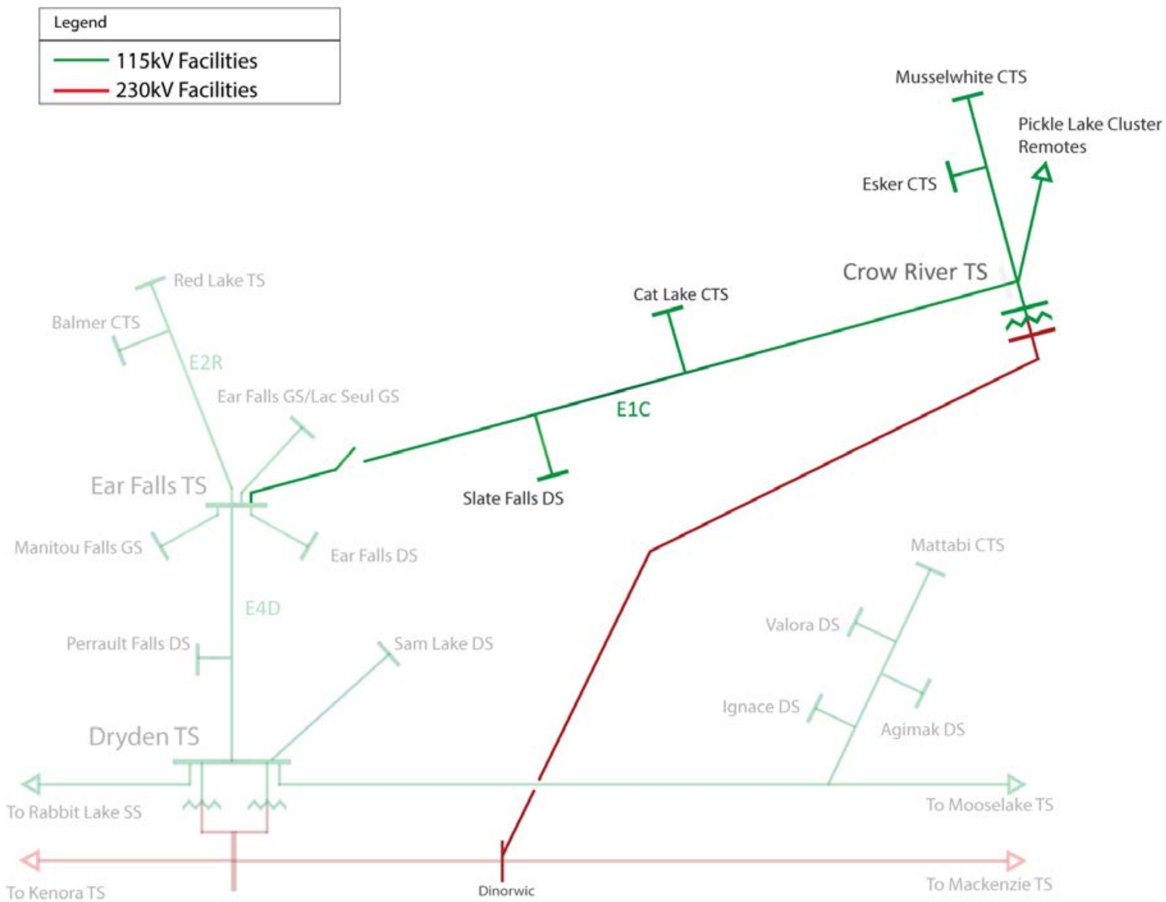


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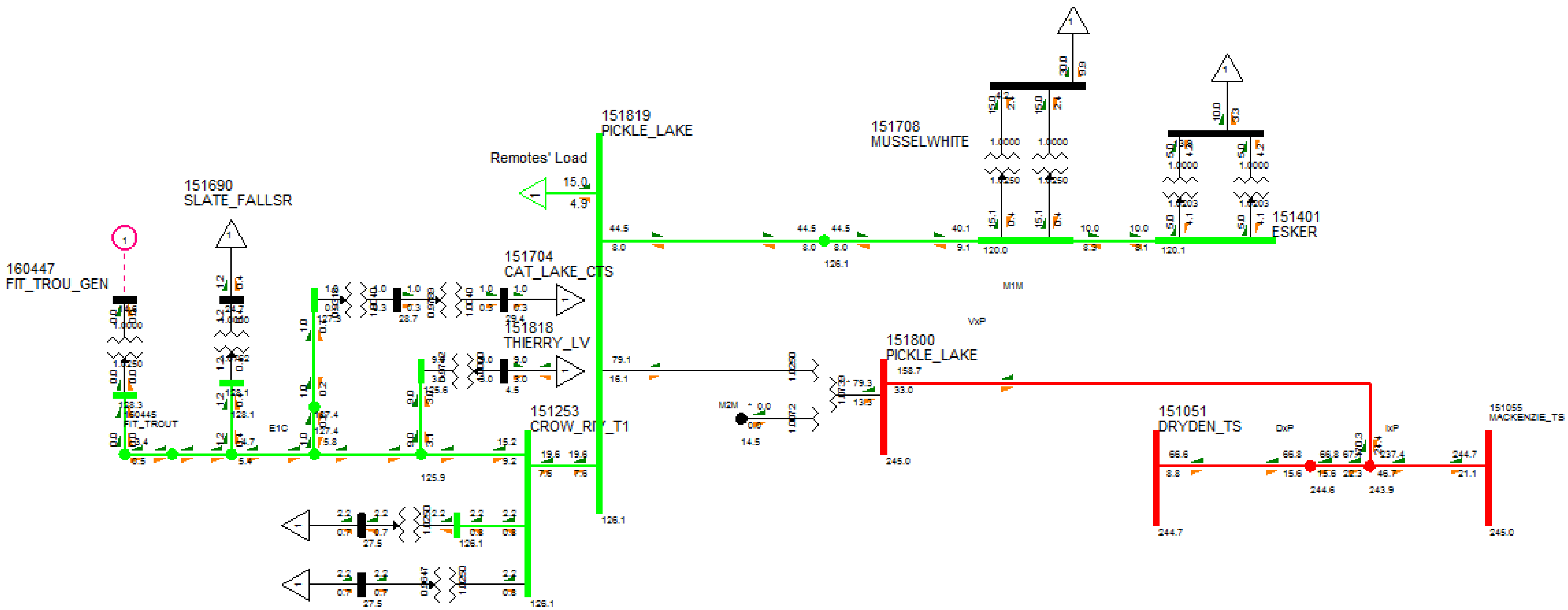
Figure 21: 230 kV Line Option Pickle Lake Subsystem Configuration



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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

Recommendation	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
Upgrade E4D and E2R and Transfer of Pickle Lake load to new line to Pickle Lake	34 MW	95 MW	100 MW	109 MW	136 MW
	35 MW	130 MW			

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

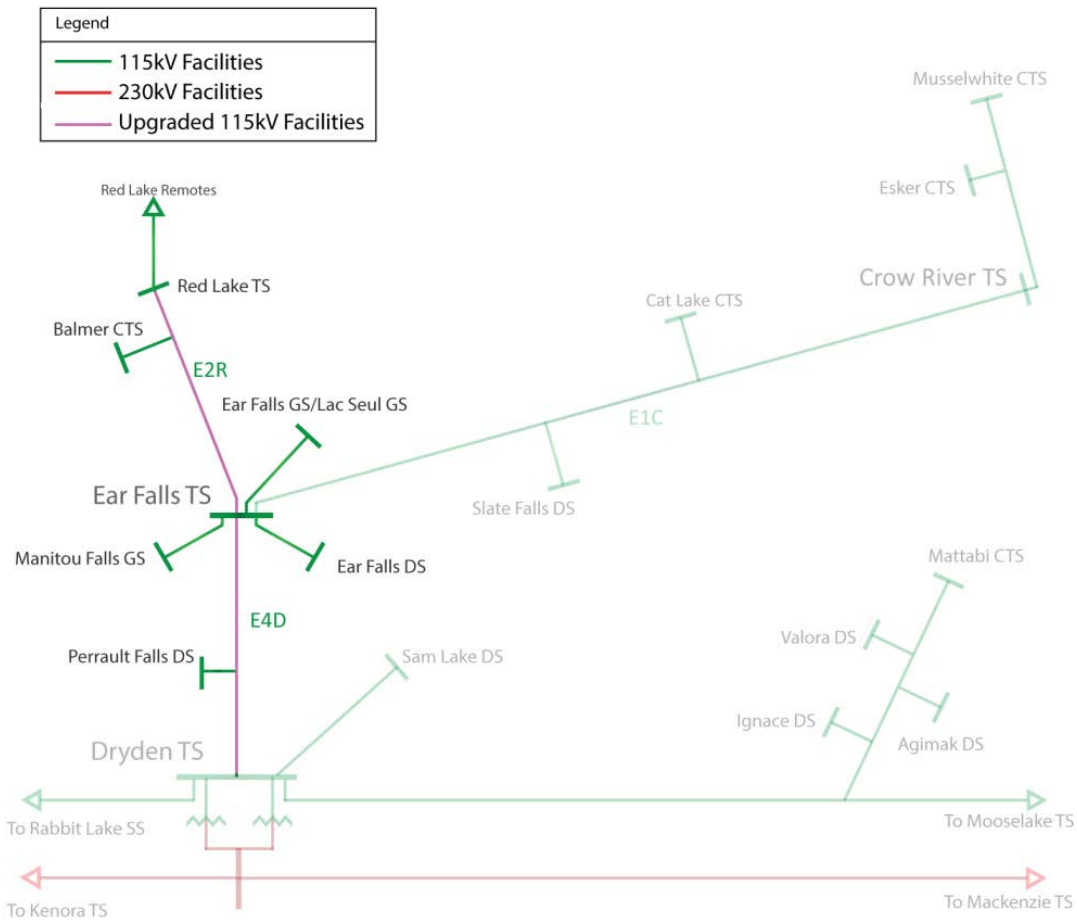

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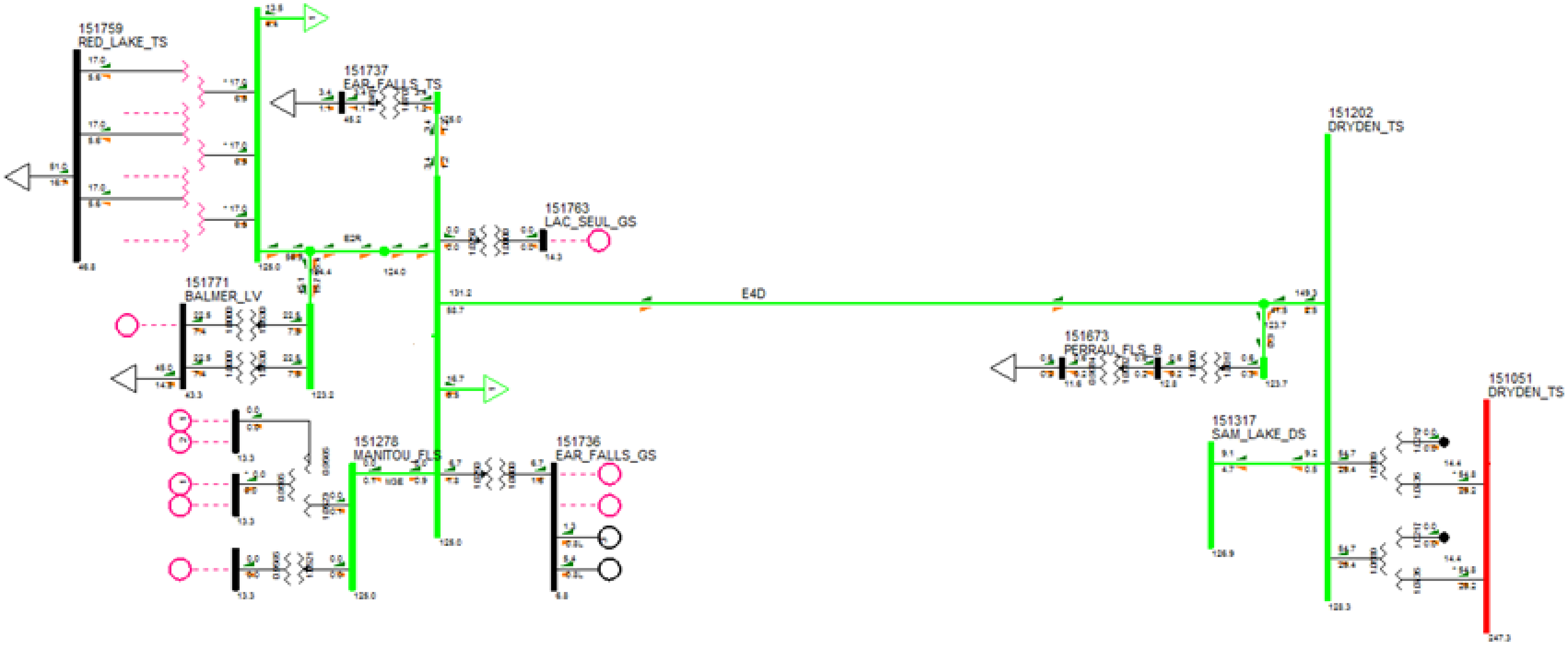
Figure 23: E4D and E2R Upgrade Red Lake Subsystem Configuration



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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

<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>CNG Generation at Pickle Lake (38 MW)</td><td>19 MW</td><td>43 MW</td><td rowspan="4">41 MW</td><td rowspan="4">78 MW</td><td rowspan="4">90 MW</td></tr>
<tr><td>CNG Generation at Pickle Lake (47.5 MW)</td><td>23.5 MW</td><td>47.5 MW</td></tr>
<tr><td>CNG Generation at Pickle Lake (76 MW)</td><td>57 MW</td><td>81 MW</td></tr>
<tr><td>CNG Generation at Pickle Lake (85.5 MW)</td><td>66.5 MW</td><td>90.5 MW</td></tr>
</table>

*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

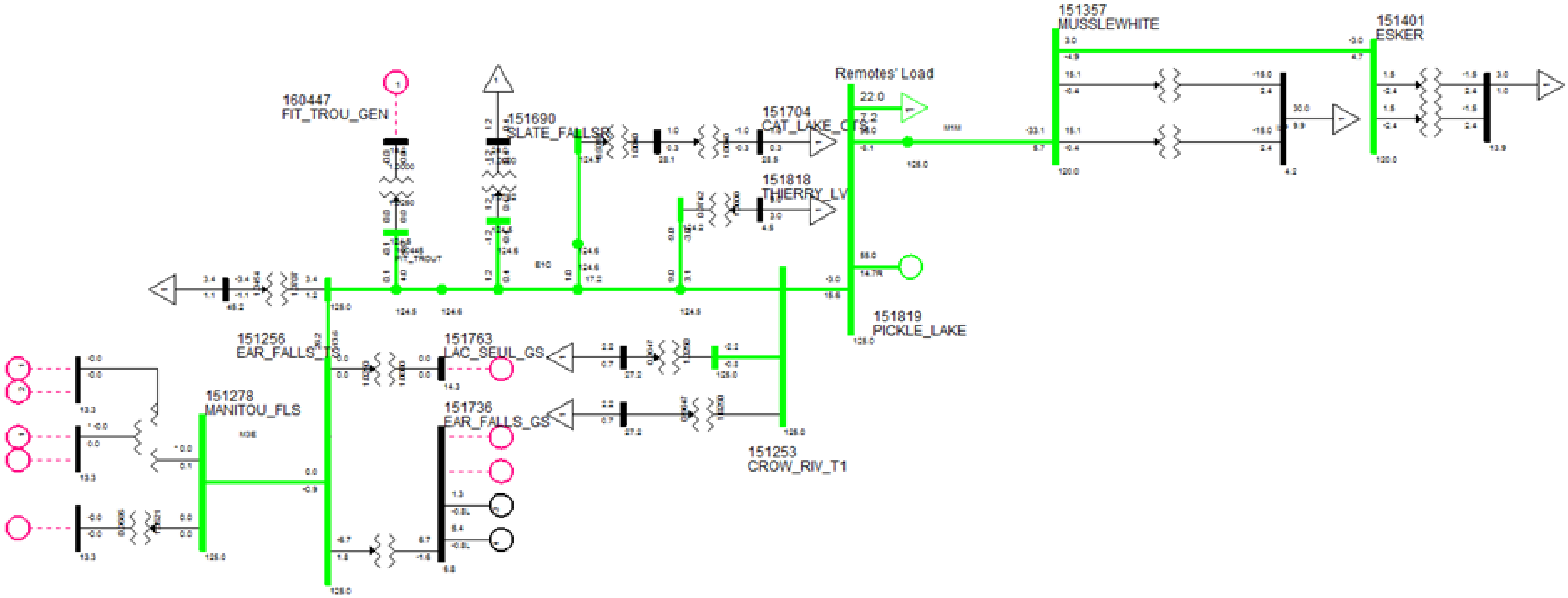
Table 68: Summary of Cost for 85.5 MW of CNG Generation in Pickle Lake Subsystem

	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



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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.

Planning Assessment of Near-Term Option

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.

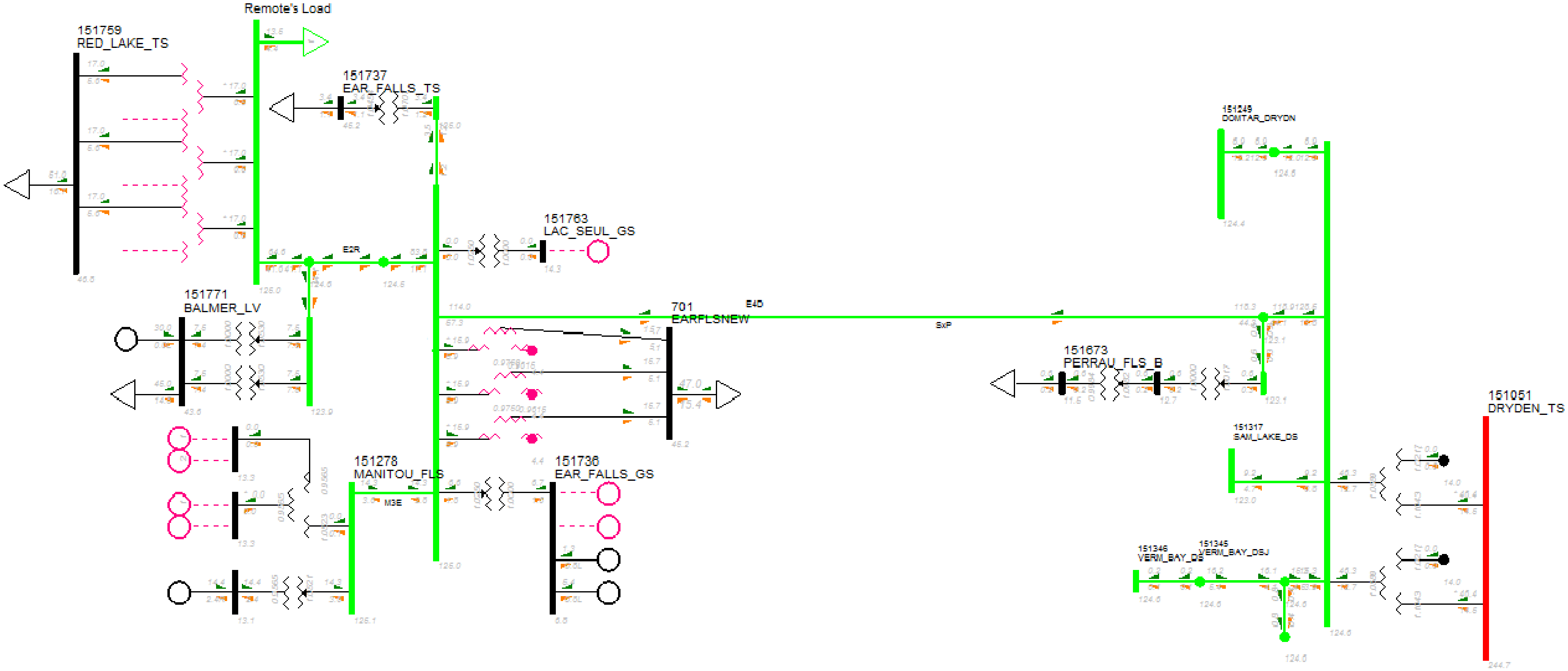
Table 71: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

	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



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Planning Assessment of Medium- and Long-Term Options

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

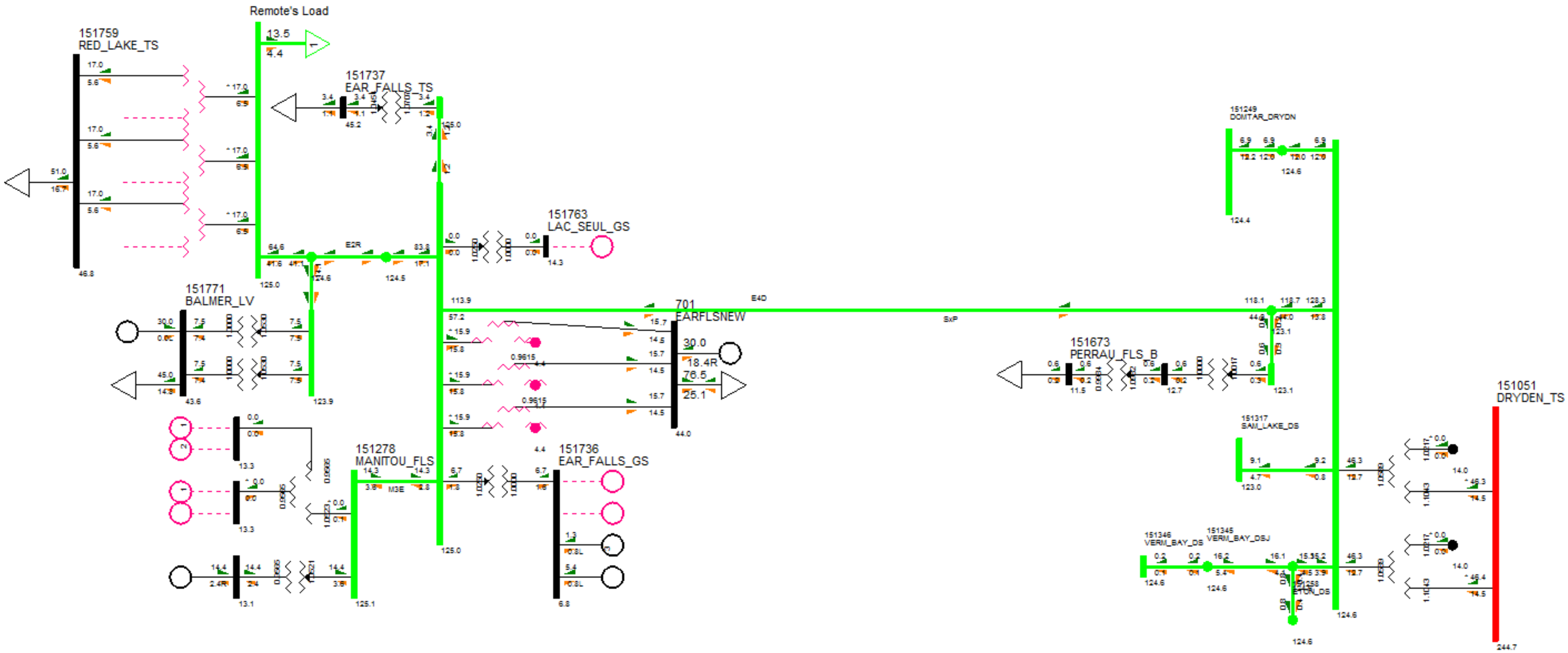
Table 76: Summary of Cost for 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

	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



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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

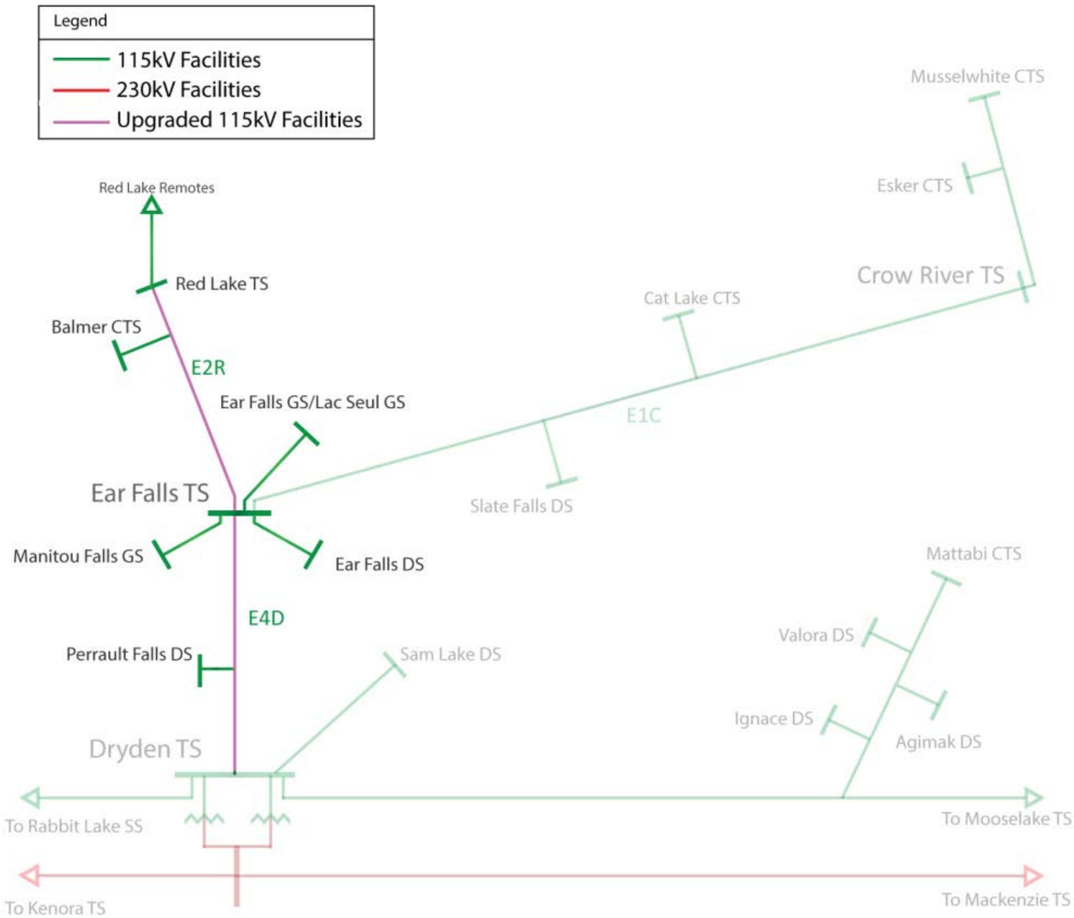
The existing lines serving the Red Lake subsystem are E4D, from Dryden to Ear Falls, and E2R, from Ear Falls to Red Lake. E4D has a thermal rating of 470 amps, and a transfer capability of 100 MVA (at 125 kV nominal voltage), while E2R a thermal rating of 420 amps, and a transfer capability of 91 MVA (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

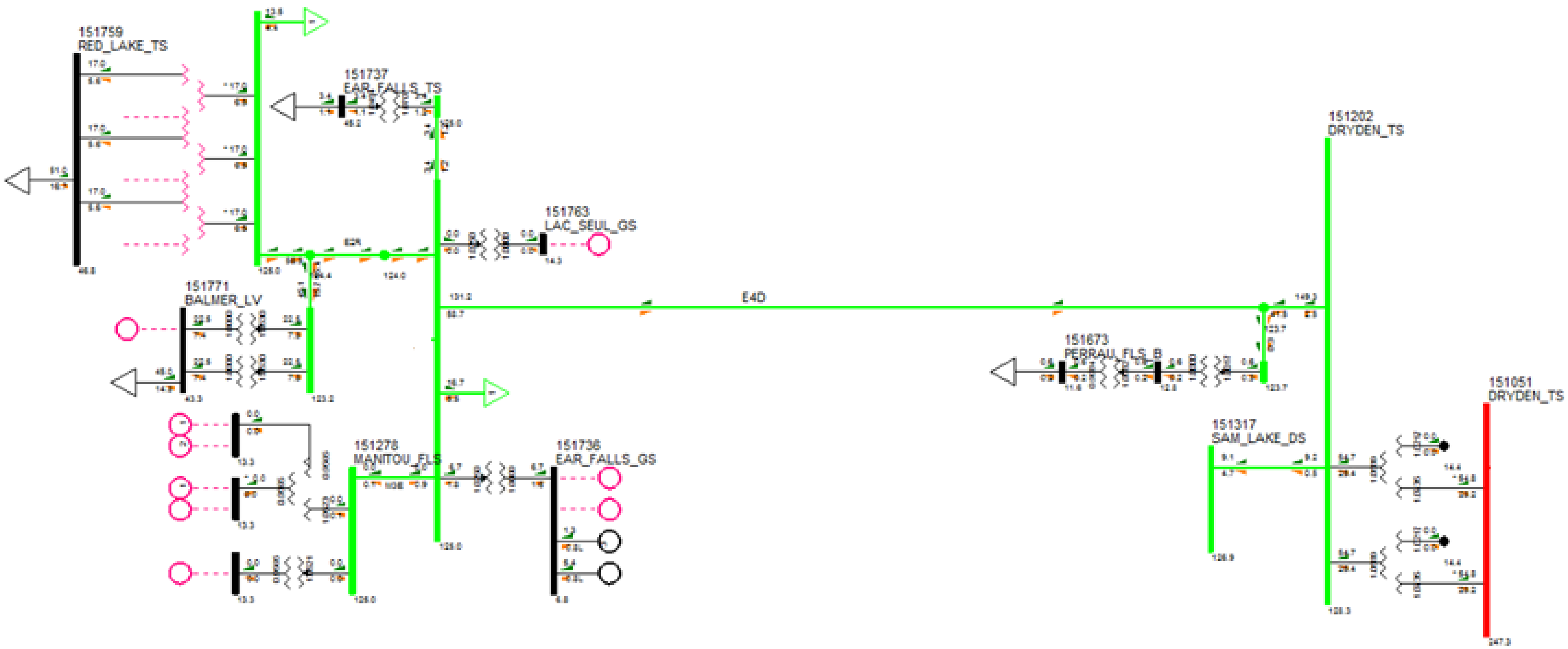


Hydro One has indicated that upgrading these lines as well as the installation of required voltage control devices could be completed within the near-term period. Table 86 below shows the cost breakdown of the upgrade option which includes the required voltage control devices. Figure 28 shows the load 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



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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

<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>New 115 kV line from Dryden to Ear Falls with less compensation (160 MW)</td><td>30 MW</td><td>160 MW</td><td rowspan="2">100 MW</td><td rowspan="2">109 MW</td><td rowspan="2">136 MW</td></tr>
<tr><td>New 115 kV line from Dryden to Ear Falls with more compensation (190 MW)</td><td>60 MW</td><td>190 MW</td></tr>
</table>

Figure 29: New 115 kV line to Ear Falls Diagram

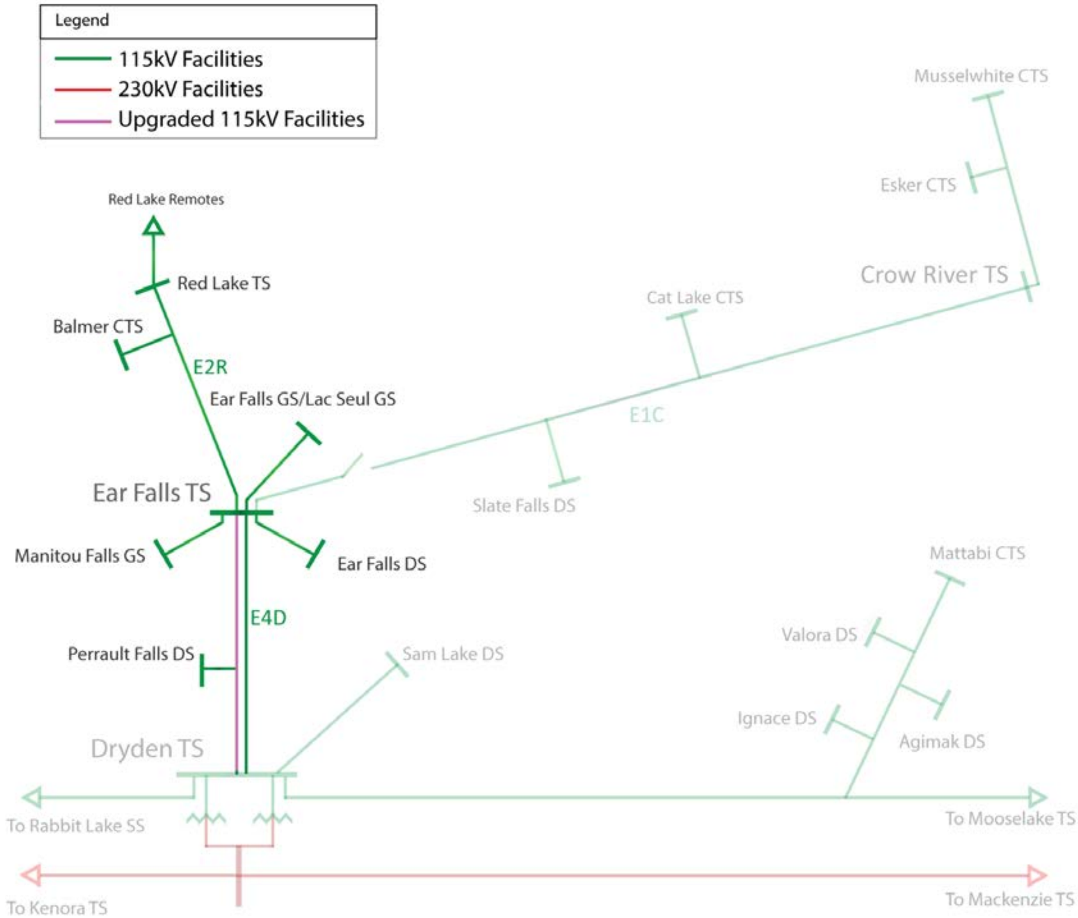


Figure 30, shows the peak load flow case for this option. Voltage at Ear Falls TS is maintained within a healthy range of 120 kV to 125 kV.

Table 88 and Table 89 summarize the annual cashflows and cumulative NPV cost for the options.

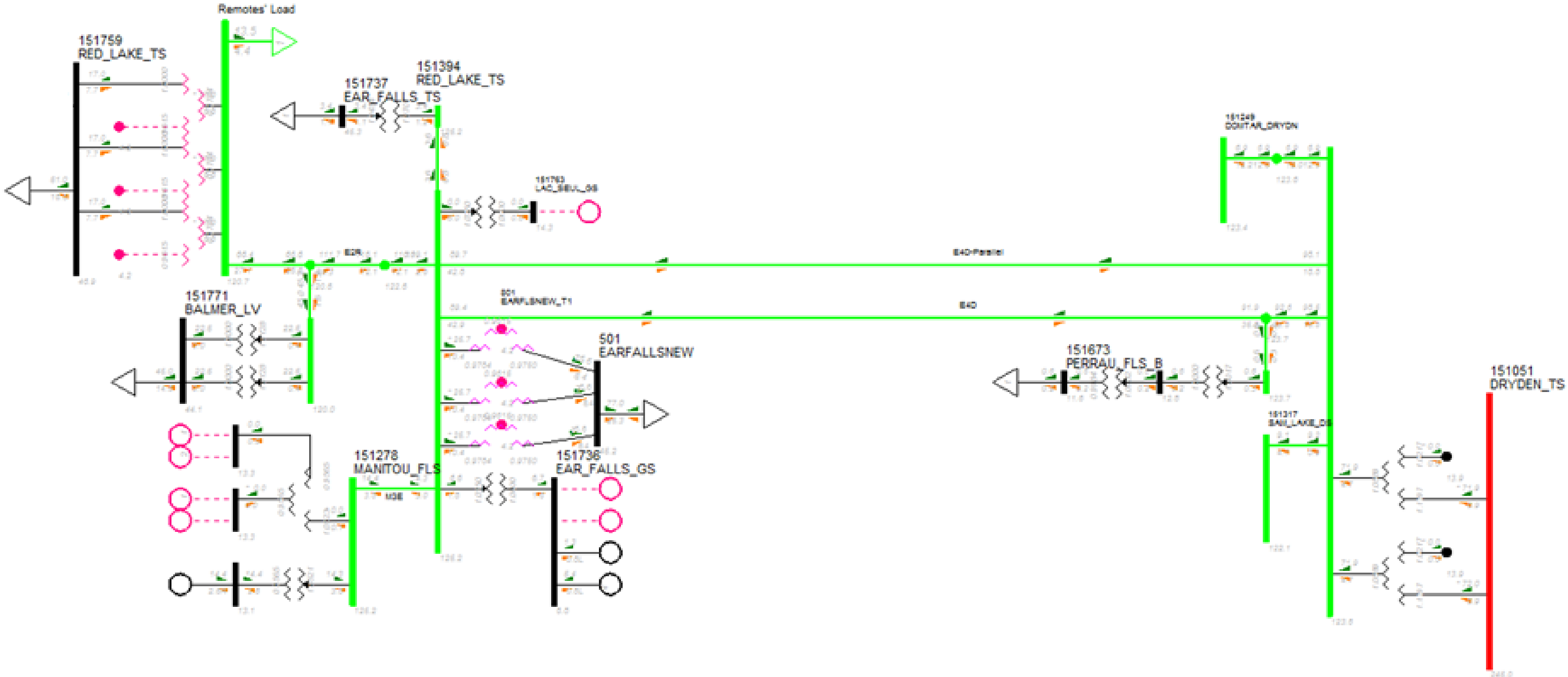
Table 88: 115 kV line to Ear Falls 160 MW LMC Cost Summary

	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



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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

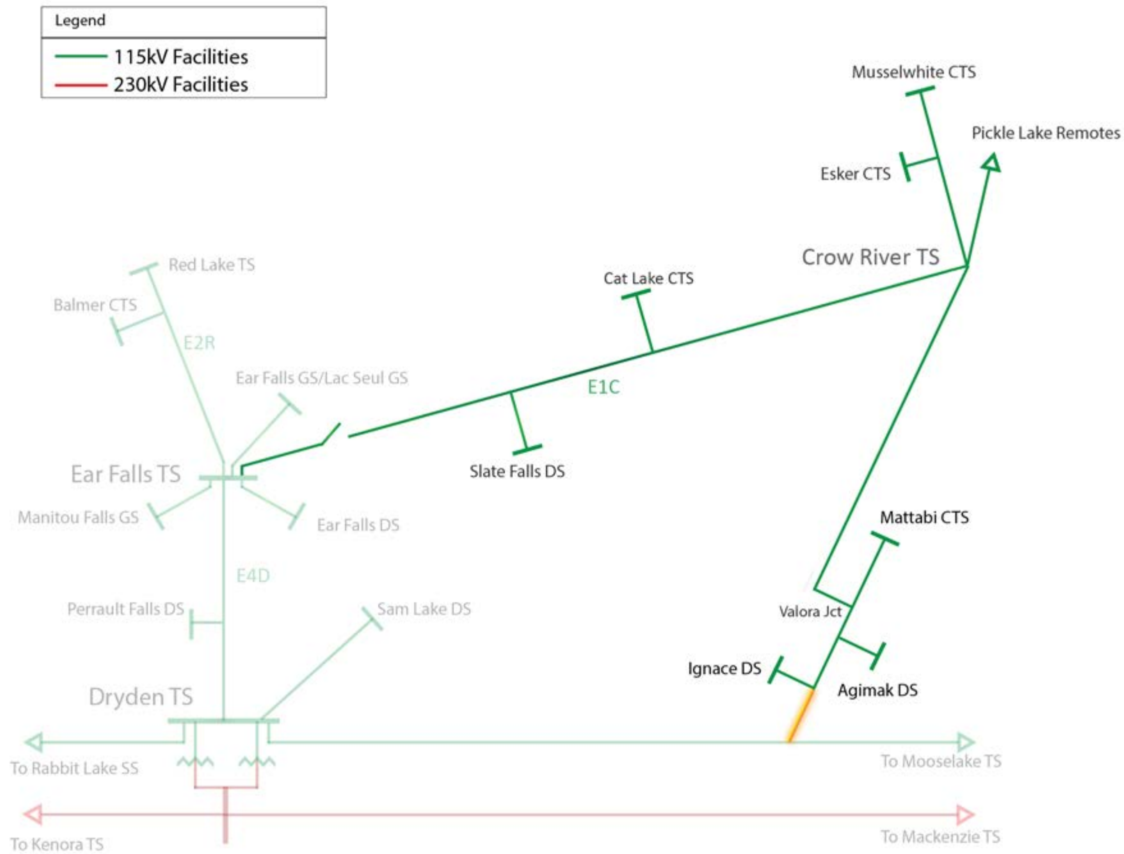
This option is to install a new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker and terminating at Crow River DS in Pickle Lake. Currently, there are a number of short sections of 29M1 between Ignace and Valora which have thermal ratings which are lower than 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.

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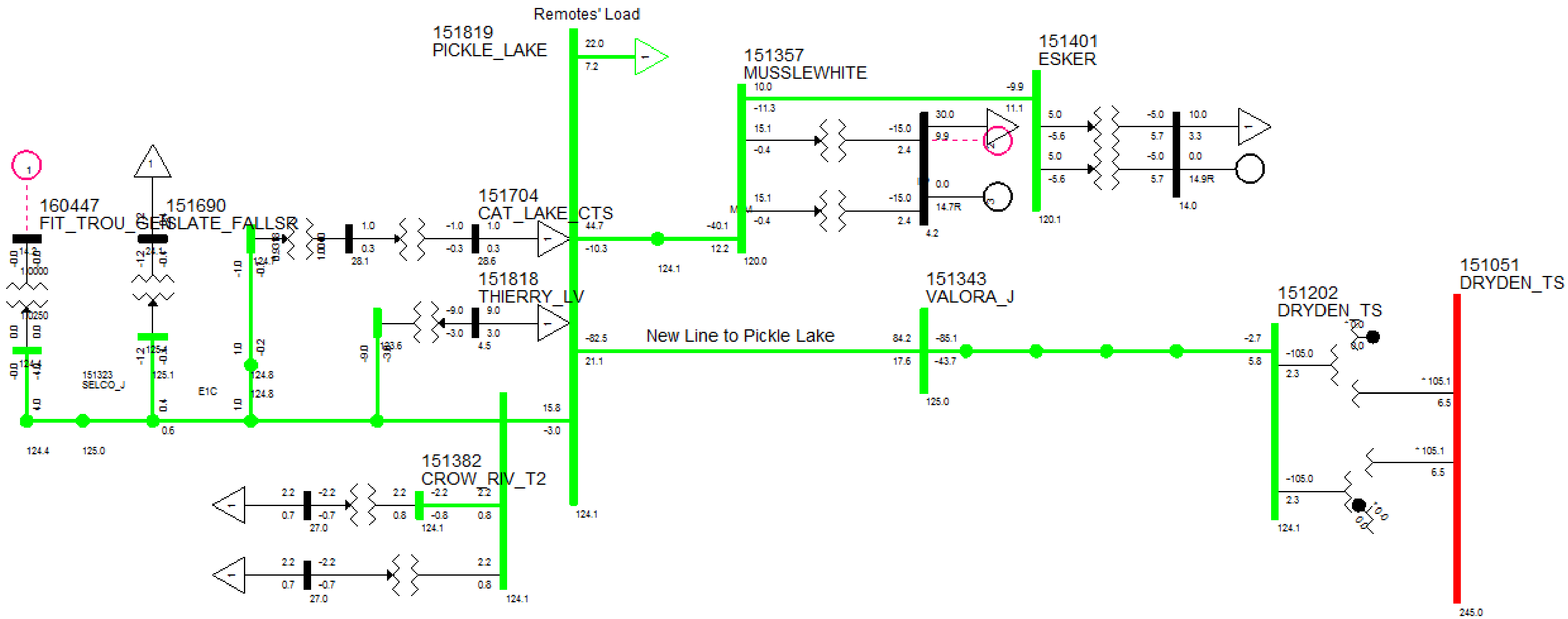
Figure 32 shows the load flow case during peak load. The Pickle Lake bus voltage is maintained in a healthy range of 120 kV to 125 kV.

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

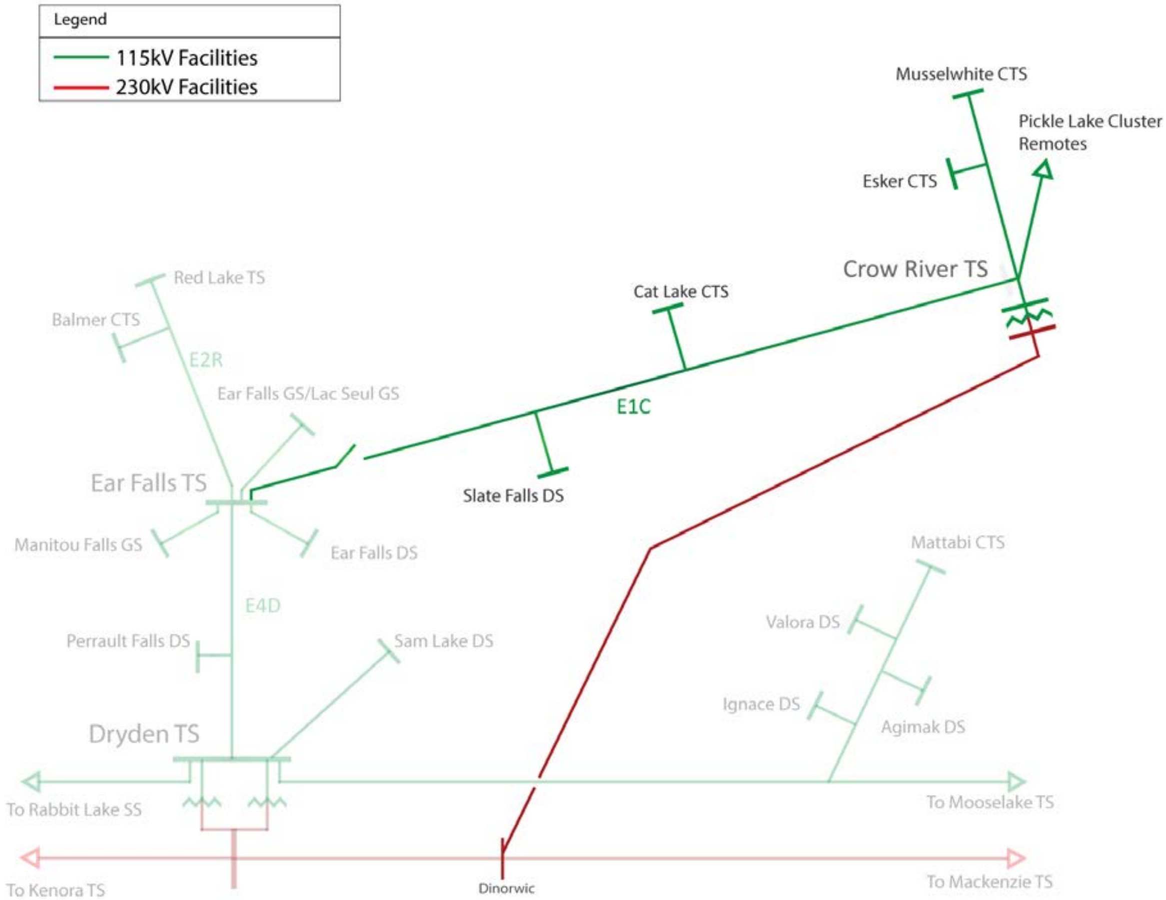
This option is to install a new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker running to Pickle Lake terminating at Crow River DS or at a new 230 kV station where a new 230/115 kV autotransformer will be installed.

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.

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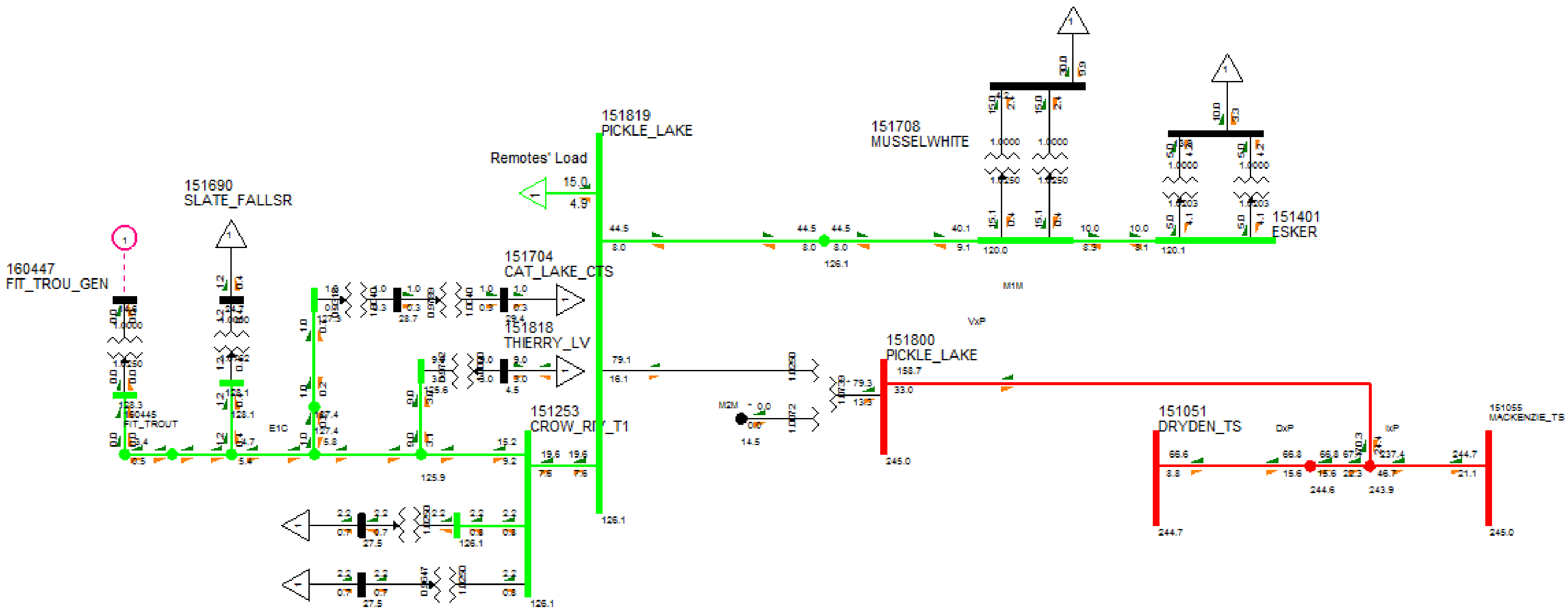
Table 93: 230 kV line to Pickle Lake Cost Summary for LMC up to 78 MW

	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



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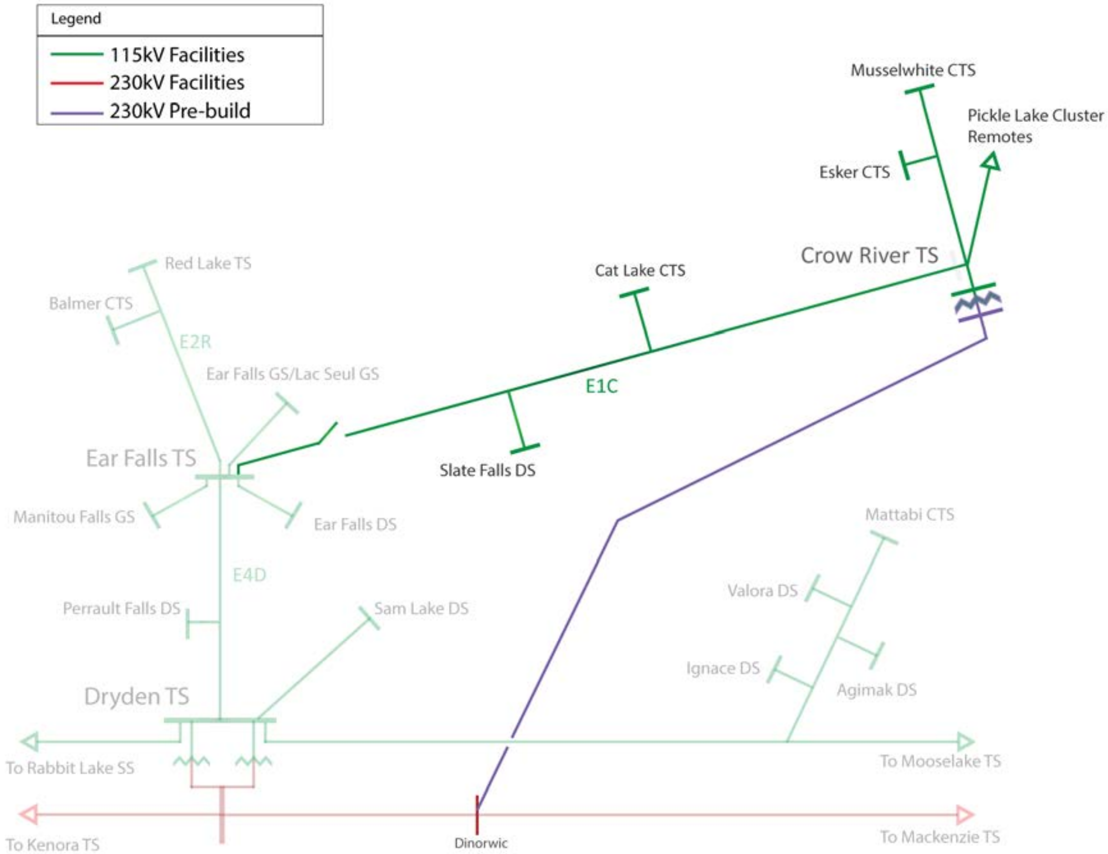
Pre-build 230 kV Line to Pickle Lake

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).

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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

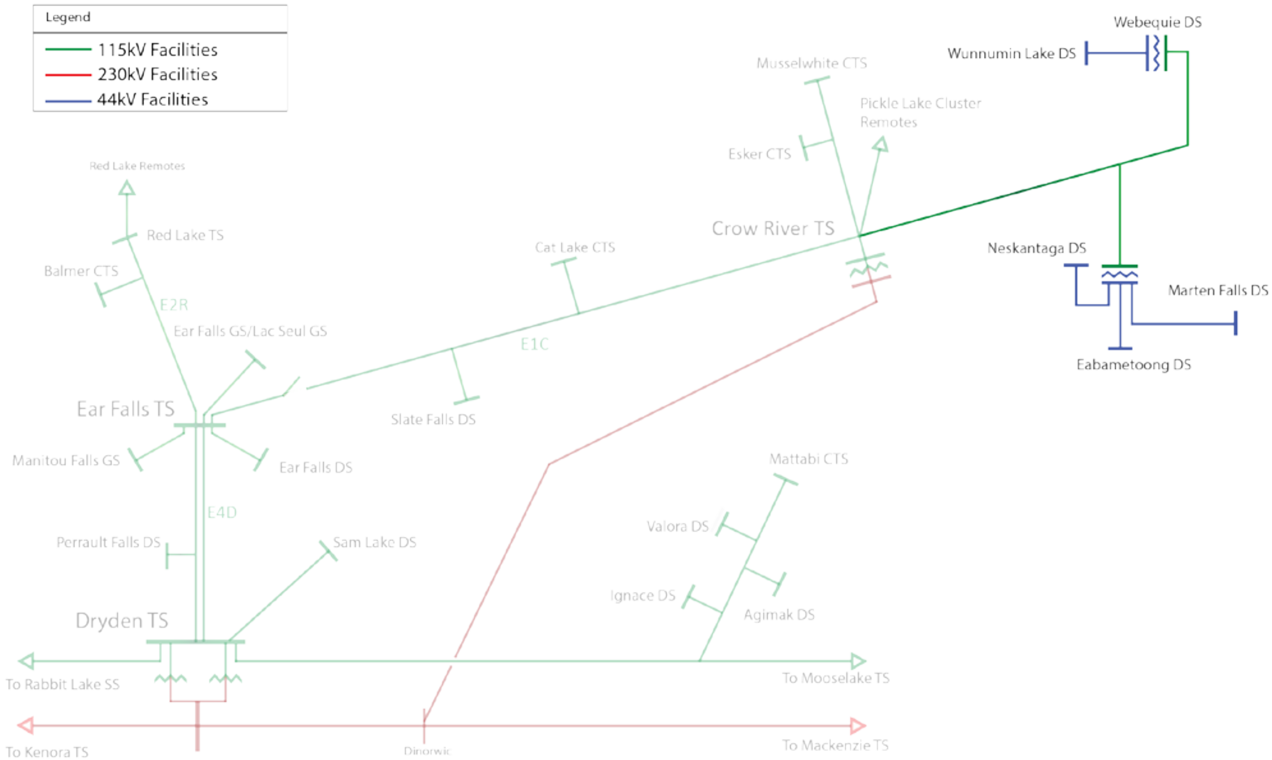

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Table 98: 115 kV line from Pickle Lake to Ring of Fire Subsystem Remote Communities Cost Summary

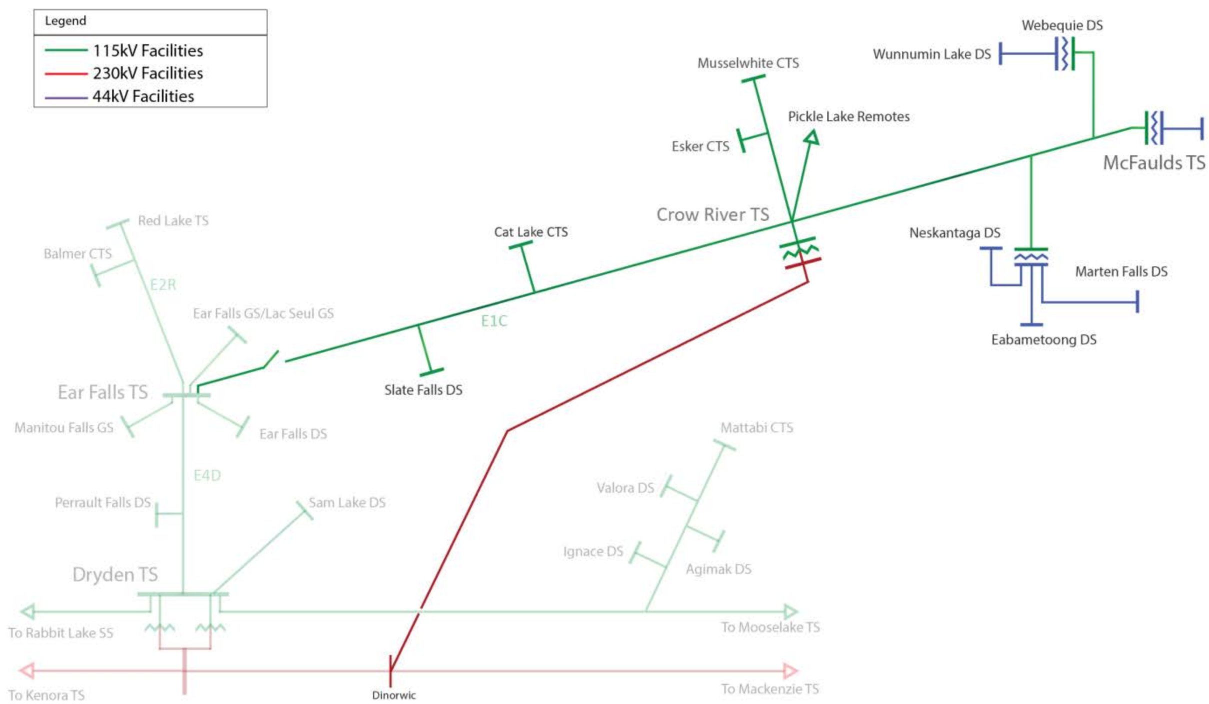
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						94.3														
Station cost						6.6														
O&M						1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	101.9	1.0	1.0	1.0	1.0	1.0	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.

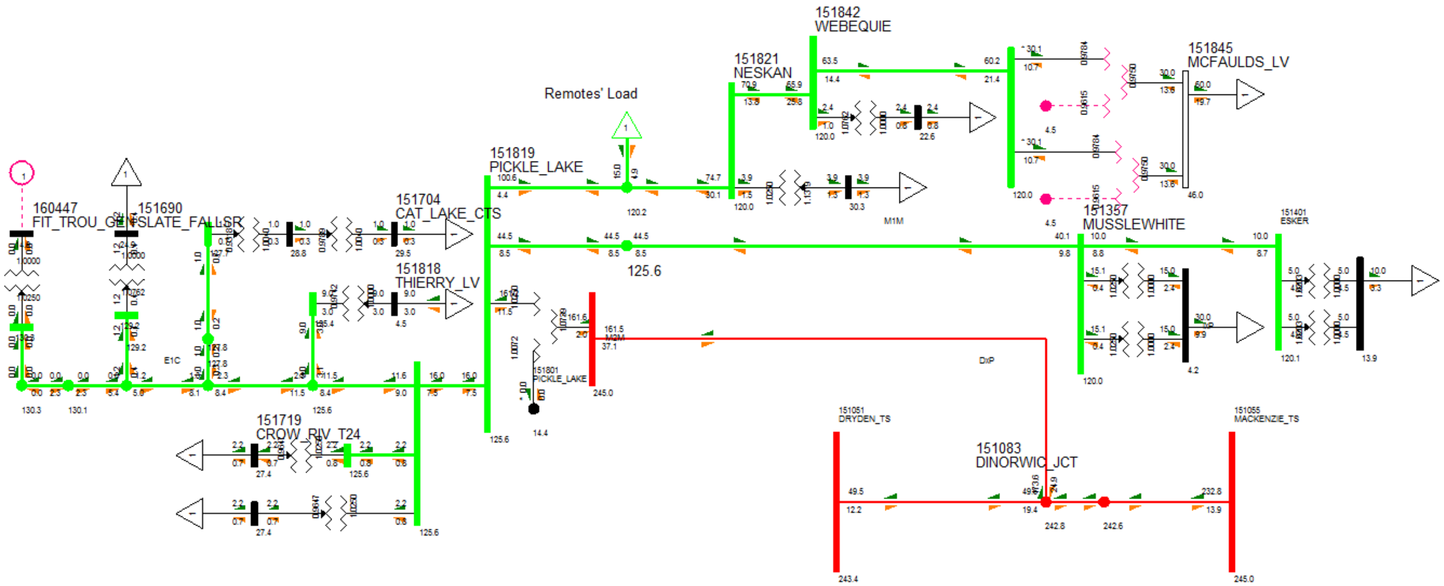
Table 99: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 29 MW

	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



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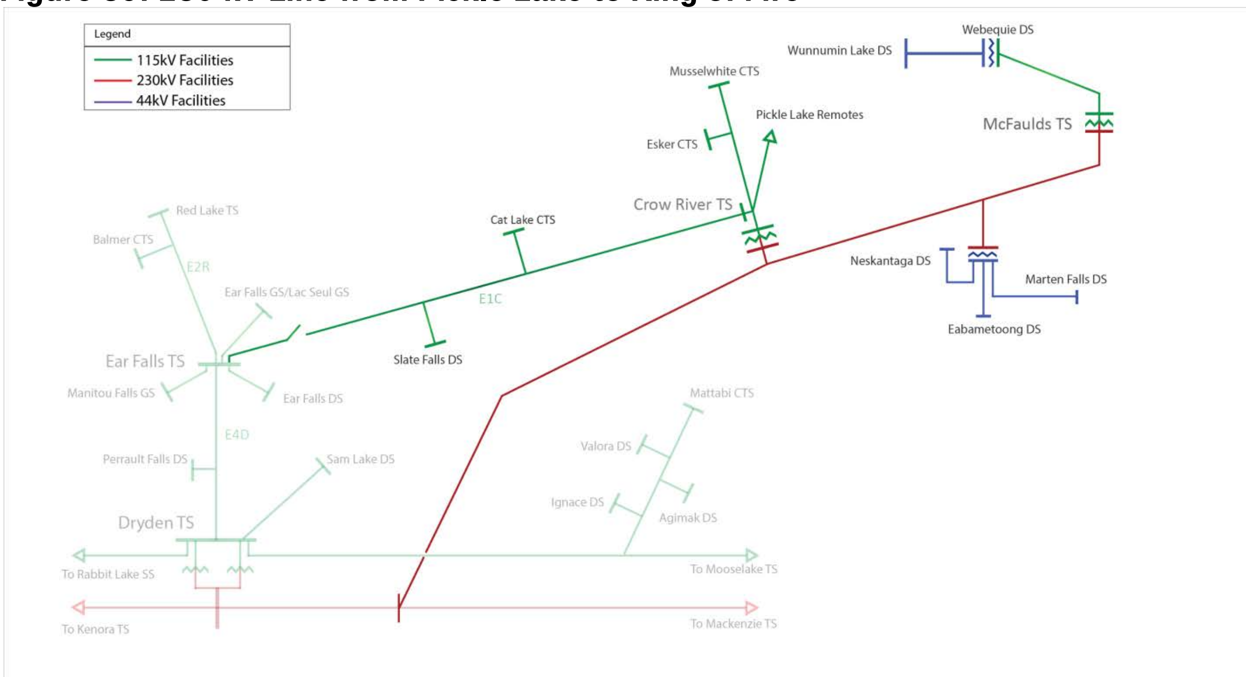
230 kV Line from Pickle Lake to Ring of Fire

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

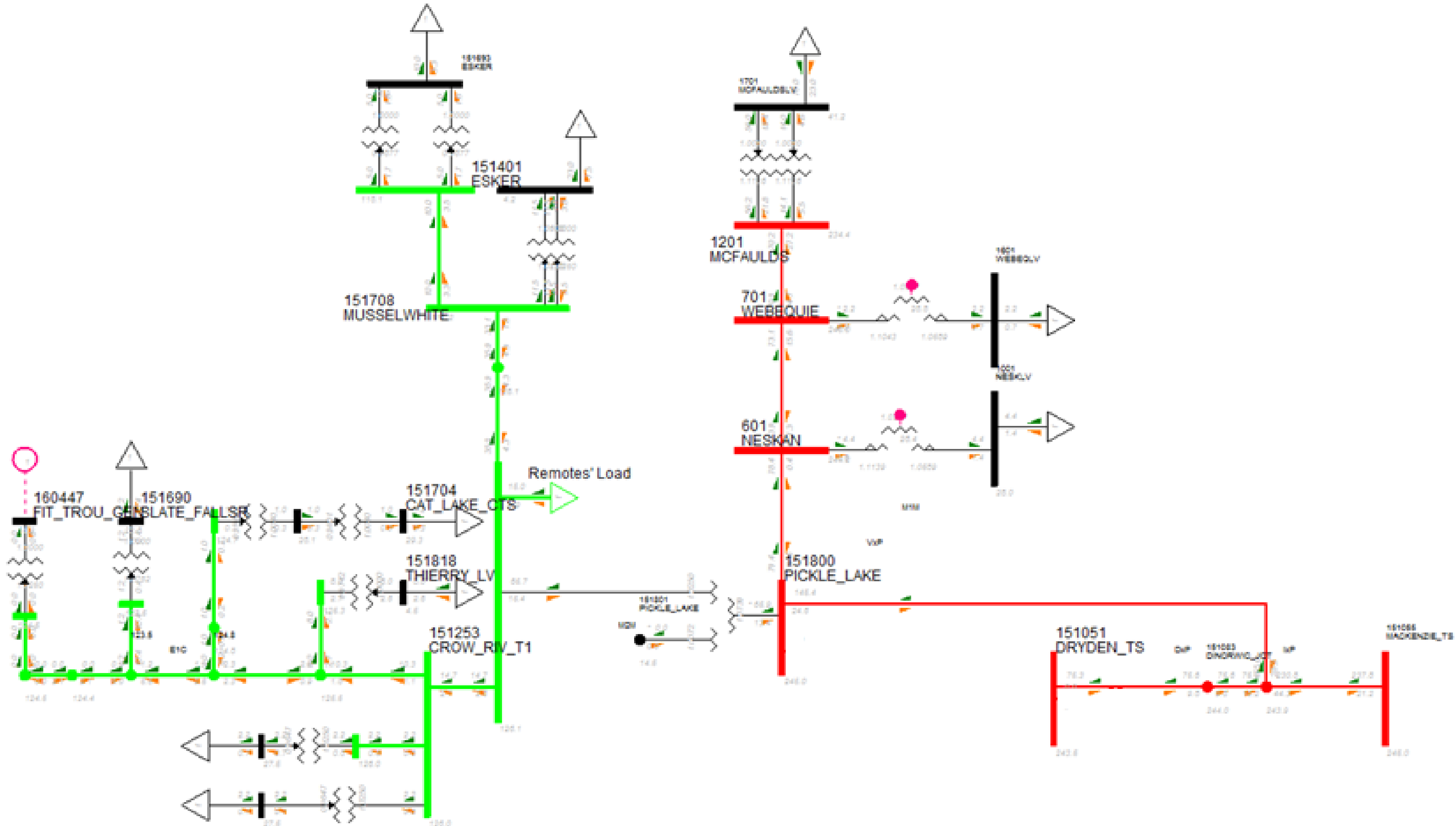


A prorated portion of the costs for new a 230 kV transmission line and station from the Dryden area to Pickle Lake is included in the cost of this option, as shown in the cost summary in Table 101 below.

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																			

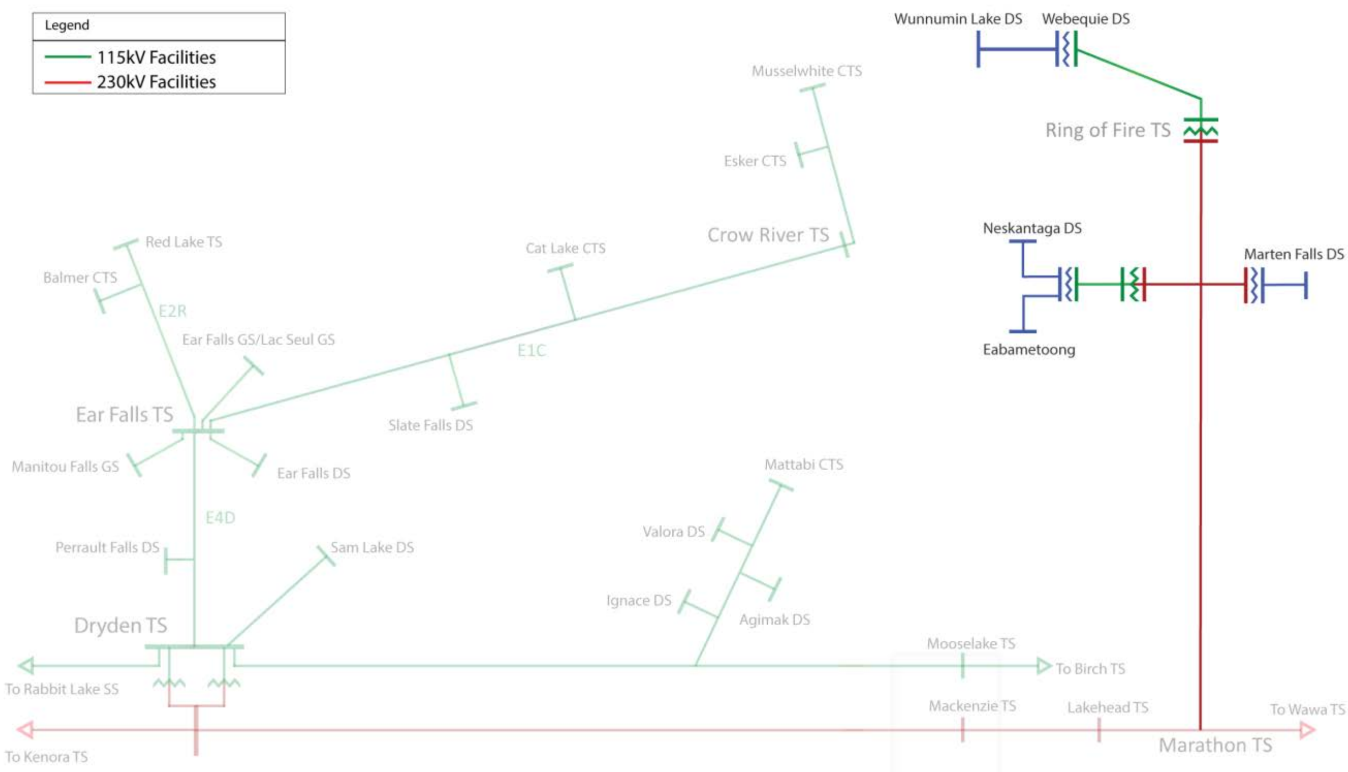
Figure 40: 230 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration



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



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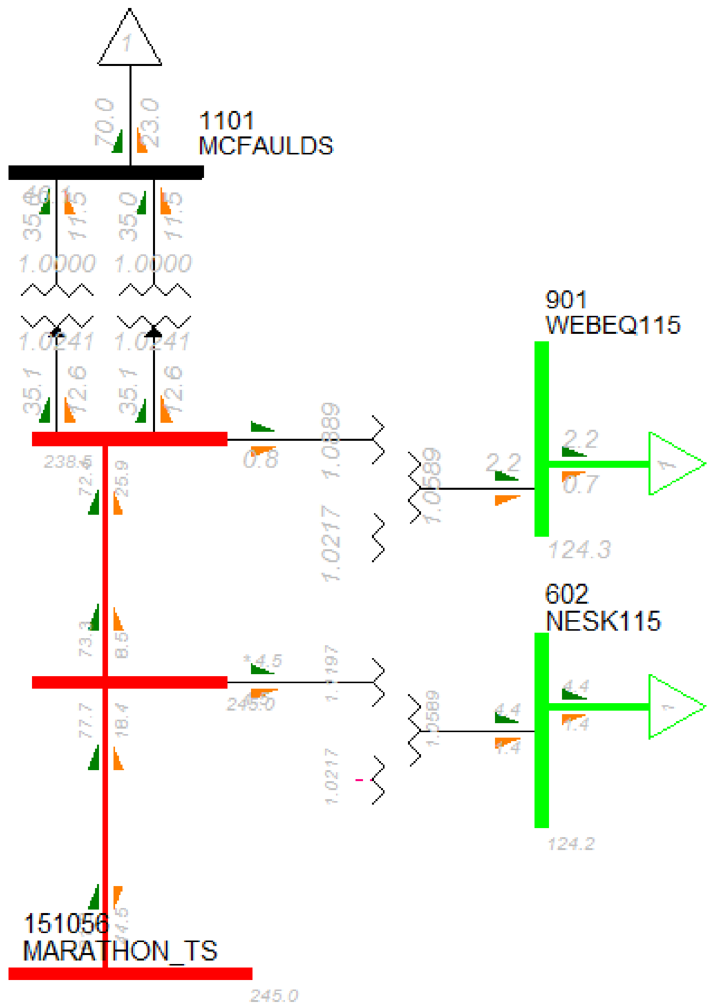
The LMC of the Ring of Fire subsystem for this option is 77 MW. This includes 7 MW for the communities on the line as well as 70 MW at the Ring of Fire. A summary of the cost for this option can be found in Table 102 below.

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

Appendix C: Order-in-Council from the Minister of Energy

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

July 29, 2016

Ms Rosemarie Leclair
Chair and Chief Executive Officer
Ontario Energy Board
2300 Yonge Street
PO Box 2319
Toronto ON M4P 1E4

Dear Ms Leclair:

The connection of remote First Nation communities was identified as a priority project in the 2013 Long-Term Energy Plan. This project will reduce reliance on diesel generation and bring a number of environmental, social and economic benefits to these First Nation communities. Under the authority of section 28.6.1 of the *Ontario Energy Board Act, 1998,* I have, with the approval of the Lieutenant Governor in Council, issued a directive with regard to the expansion of the transmission system by developing the Remotes Connection Project and the Line to Pickle Lake.

The Directive was approved by Order-in-Council on July 19, 2016, and both the Order-in-Council and Directive are attached to this letter. Please do not hesitate to contact my office with any questions.

Sincerely,

Glenn Thibeault
Minister

Enclosures

c: Dan Moulton, Senior Advisor (Communications), Ministry of Energy

Ontario

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor of Ontario, by and with the advice and concurrence of the Executive Council of Ontario, orders that:

Sur la recommandation de la personne soussignée, la lieutenante-gouverneure de l'Ontario, sur l'avis et avec le consentement du Conseil exécutif de l'Ontario, décrète ce qui suit:

WHEREAS Ontario's 2013 Long-Term Energy Plan stated that the connection of twenty one remote First Nation communities and the Line to Pickle Lake are priorities for Ontario.

AND WHEREAS Ontario has determined the benefit of expanding Ontario's transmission system in order to connect the sixteen remote First Nation communities in Appendix A to the provincial electricity grid (the "Remotes Connection Project");

AND WHEREAS the Remotes Connection Project will also require enhancement of the existing transmission system that includes a new transmission line originating in or at a point between Ignace and Dryden to increase supply to Pickle Lake (the Line to Pickle Lake);

AND WHEREAS the Government has determined that the Remotes Connection Project and the Line to Pickle Lake should be undertaken by a transmitter that is best positioned to connect remote First Nation communities in the most timely and cost-efficient manner that protects ratepayer interests;

AND WHEREAS the Government has determined that the preferred manner of proceeding is to require 2472883 Ontario Limited on behalf of Wataynikaneyap Power LP to undertake the development of the Line to Pickle Lake and the Remotes Connection Project, including any and all steps which are deemed to be necessary and desirable in order to seek required approvals;

AND WHEREAS the Minister of Energy has, with the approval of the Lieutenant Governor in Council, the authority to issue Directives pursuant to section 28.6.1 of the *Ontario Energy Board Act, 1998,* which relate to the construction, expansion or re-enforcement of transmission systems;

NOW THEREFORE the Directive attached hereto is approved.

\- - - - - - - -

ATTENDU QUE le plan énergétique à long terme de l'Ontario de 2013 a indiqué que le branchement de vingt-et-une collectivités éloignées des Premières Nations et la ligne vers Pickle Lake constituent des priorités pour l'Ontario.

ET ATTENDU QUE l'Ontario a déterminé l'avantage de prolonger le système de transport d'électricité de l'Ontario afin de brancher les seize collectivités éloignées des Premières Nations figurant à l'annexe A au réseau provincial d'électricité (« le projet de branchement des communautés éloignées »);

ET ATTENDU QUE le projet de branchement des communautés éloignées nécessitera également d'apporter des améliorations au système existant de transport d'électricité, y compris l'ajout d'une nouvelle ligne provenant d'un point entre Ignace et Dryden pour augmenter l'alimentation de Pickle Lake (la ligne vers Pickle Lake);

ET ATTENDU QUE le gouvernement a déterminé que le projet de branchement des communautés éloignées et la ligne vers Pickle Lake devraient être entrepris par le transporteur le mieux placé pour assurer le branchement des communautés éloignées des Premières Nations aussi rapidement et efficacement que possible afin d'assurer la protection des intérêts des usagers de l'électricité;

ET ATTENDU QUE le gouvernement a déterminé que la manière privilégiée pour ce faire est d'engager 2472883 Ontario Limited au nom de Wataynikaneyap Power LP pour entreprendre les travaux de la ligne de Pickle Lake et du projet de branchement des communautés éloignées, y compris toutes les étapes jugées nécessaires et souhaitables en vue de l'obtention des approbations nécessaires;

ET ATTENDU QUE le ministre de l'Énergie détient, avec l'approbation du lieutenant-gouverneur en conseil, l'autorité de publier des directives en vertu de l'article 28.6.1 de la *Loi de 1998 sur la*

Commission de l'énergie de l'Ontario liées à la construction, à l'expansion ou au renforcement des systèmes de transport d'électricité;

POUR CES MOTIFS, la directive jointe aux présentes est approuvée.

Recommended: Minister of Energy
Recommandé par: Ministre de l'Énergie

Concurred: Chair of Cabinet
Appuyé par: Le président/la présidente du Conseil des ministres,

Approved and Ordered:
Approuvé et décrété le: JUL 20 2016

Lieutenant Governor
La lieutenante-gouverneure

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Glenn Thibeault, hereby direct the Ontario Energy Board ("the Board") pursuant to section 28.6.1 of the *Ontario Energy Board Act, 1998* as follows:

1. The Board shall amend the conditions of 2472883 Ontario Limited on behalf of Wataynikaneyap Power LP's ("Wataynikaneyap Power LP") electricity transmission licence to include a requirement that Wataynikaneyap Power LP proceed to do the following related to expansion of the transmission system to connect the sixteen remote First Nation communities listed in Appendix A (collectively the "Remote Communities") to the provincial electricity grid:

    (i) Develop and seek approvals for a transmission line, which shall be composed of a new 230 kV line originating at a point between Ignace and Dryden and terminating in Pickle Lake (the "Line to Pickle Lake"). The development of the Line to Pickle Lake shall accord with the scope recommended by the Independent Electricity System Operator.

    (ii) Develop and seek approvals for the transmission lines extending north from Red Lake and Pickle Lake required to connect the Remote Communities to the provincial electricity grid. The development of these transmission lines shall accord with the scope supported by the Independent Electricity System Operator.

2. The Board shall require that Wataynikaneyap Power LP provide such reporting to the Board as the Board may consider appropriate, with respect to budget, timing, and risks in relation to the development of the projects referred to in paragraph 1.

3. The Board shall make the amendments to the electricity transmission licence of Wataynikaneyap Power LP without holding a hearing.

Minister of Energy

Appendix A

1. Sandy Lake
2. Poplar Hill
3. Deer Lake
4. North Spirit Lake
5. Kee-Way-Win
6. Kingfisher
7. Wawakapewin
8. Kasabonika Lake
9. Wunnumin
10. Wapekeka
11. Kitchenuhmaykoosib Inninuwug
12. Bearskin Lake
13. Muskrat Dam Lake
14. Sachigo Lake
15. North Caribou Lake
16. Pikangikum

DIRECTIVE DU MINISTRE

DESTINATAIRE : COMMISSION DE L'ÉNERGIE DE L'ONTARIO

Je, Glenn Thibeault, émets par les présentes à la Commission de l'énergie de l'Ontario (« la commission ») en vertu de l'article 28.6.1 de la *Loi de 1998 sur la Commission de l'énergie de l'Ontario* la directive suivante :

1. La commission modifiera les conditions du permis de 2472883 Ontario Limited au nom de Wataynikaneyap Power LP (« Wataynikaneyap Power LP ») pour exiger que Wataynikaneyap Power LP procède aux travaux nécessaires à l'expansion du système de transport d'éléctricité visant à brancher les seize collectivités éloignées des Premières Nations énumérées à l'annexe A (collectivement appelées « collectivités éloignées ») au réseau provincial d'électricité :

   (i) Définir et soumettre les demandes d'approbation d'une ligne de transport d'électricité, laquelle sera composée d'une nouvelle ligne de 230 kV provenant d'un point situé entre Ignace et Dryden et se terminant à Pickle Lake (la « ligne vers Pickle Lake »). La mise en place de la ligne vers Pickle Lake sera conforme à la portée recommandée par la Société indépendante d'exploitation du réseau d'électricité.

   (ii) Définir et soumettre les demandes d'approbation des lignes de transport d'électricité s'étendant au nord à partir de Red Lake et de Pickle Lake requises pour assurer le branchement des collectivités éloignées au réseau provincial d'électricité. La mise en place de ces lignes de transport sera conforme à la portée appuyée par la Société indépendante d'exploitation du réseau d'électricité.

2. La commission exigera de Wataynikaneyap Power LP qu'elle rende compte à la commission, comme la commission le juge approprié, relativement aux budgets, au calendrier et aux risques liés à la réalisation des projets énoncés au paragraphe 1.

3. La commission apportera les modifications nécessaires au permis de transport d'électricité de Wataynikaneyap Power LP sans tenir d'audience.

Ministre de l'Énergie

Annexe A

1. Sandy Lake
2. Poplar Hill
3. Deer Lake
4. North Spirit Lake
5. Kee-Way-Win
6. Kingfisher
7. Wawakapewin
8. Kasabonika Lake
9. Wunnumin
10. Wapekeka
11. Kitchenuhmaykoosib Inninuwug
12. Bearskin Lake
13. Muskrat Dam Lake
14. Lac Sachigo
15. North Caribou Lake
16. Pikangikum

Appendix D: Customer Satisfaction Survey Results

Report on
Customer Service Research

Prepared for Hydro One
Remote Communities

August 2015

Viewpoints Research
Winnipeg, Manitoba
(204) 988-9253
www.viewpoints.ca

TABLE OF CONTENTS

EXECUTIVE SUMMARY

On behalf of Hydro One, Viewpoints Research conducted a telephone survey of 205 Hydro One Remote Communities' residential, business and government-supported organization customers from June to August 2015.

Where possible, the survey tracks findings from six previous waves of customer surveys conducted approximately every two years since 2003. Home Heating Sources

Sources of Heating Energy

Almost two thirds of respondents indicated they heat their homes primarily with wood (64%), while 16% heat primarily with electricity, 14% with oil and 5% use propane.

A majority of respondents indicated they also use a secondary source of energy to heat their homes (56%), including 36% who use electricity, 11% who use wood, 6% who mentioned oil and 3% who said propane.

More than half of respondents mentioned electricity as either their primary or secondary source of home heating energy (51%).

Appliances at Home

Eight in ten respondents have a clothes dryer (83%) and slightly fewer have an electric stove (79%), while 64% have a stand-alone freezer and 56% have an air conditioner.

Only one in three respondents have a block heater for their car or truck (33%).

Satisfaction with Electrical Service

Overall satisfaction with the electrical service they receive from Hydro One Remotes, is 91%, similar to levels recorded in 2009 (91%) and 2011 (90%), but down from 2013's high of 97%.

Reasons for Customer Satisfaction

Having electricity available when they want it continues to be the main driver of satisfaction with Hydro One electrical service (65%). Satisfaction with this attribute increased 11 points since 2013 (51%) and 25 points since 2009 (40%).

Approximately one in three customers attributed their satisfaction to good or improved service (20%), or improved reliability (12%). Satisfaction with customer service, generally, has held steady during this time, with one in ten customers indicating this is why they are satisfied (10%).

Reasons for Customer Dissatisfaction

There were 13 dissatisfied customers in this research. High rates (85%) and unreliable service (31%) were mentioned as reasons these customers are not satisfied. These reasons are consistent with those given in past waves of research.

Perceptions of Reliability

The proportion of customers who believe the reliability of their hydro service has improved in the past few years has remained at or above 24% since 2009. This year, 25% said they believe reliability has improved, while two thirds of customers said it has stayed about the same (67%).

Bill Payment

More than 7 in 10 customers indicated they are the person who usually (67%) or sometimes (5%) pays the hydro bill.

Among those who said they usually or sometimes pays the hydro bill (N=134), perceptions regarding the accuracy of Hydro One's billing has dropped somewhat since 2013 but is still among the highest levels recorded since 2003. In this wave 25% said their Hydro One bill is always correct, down from 36% in 2013 but higher than 2011 when it was 22%. In addition, 48% of respondents said their bill is usually correct, for a total of 73%, down 6 points over 2013 results. In total, 13% of customers said their bills were either not correct very often (6%) or never correct (7%), up 7 points over 2013 results. Consistent with previous years, 15% of respondents were unsure how to answer this question.

Customer Contact

Four in ten customers said they contacted Hydro One in the past year (42%) compared to 38% in 2013 and 44% in 2011. As in previous years, the most common reason customers contacted the utility was to discuss their bill (26%). Other reasons for contact include customers needing information (17%) or the power being out (9%).

Customer satisfaction with how Hydro One Remotes handled their contact dropped 12 points to 76% after 2013's record high of 88%, but is still the second highest satisfaction rating since tracking began. Those who said they were very satisfied with their contact with Hydro One is down 13 points to 33%, its lowest level since 2007 (25%).

Factors Driving Perceptions & Satisfaction with Service

The research tested customers' agreement with a number of statements related to customer service, to explore customers' experiences and perceptions in key service areas. Hydro One Remote Communities scored best at **dealing with emergencies** (80% agree overall) and **staff being polite and friendly** (75%). Customers were less likely to agree that **when they call the Hydro One office someone usually answers quickly,** though a majority still agreed (62%).

Agreement with each of these statements dropped when compared to results in 2013 and, in the case of the first two statements, to their lowest levels since tracking began. Overall agreement with the third statement dropped three points to 62%, one point higher than its lowest level in 2011 (61%).

What Hydro One Can Do to Improve Service to Customers

When asked what Hydro One Remotes could be doing to improve service to customers, the most frequently mentioned improvement is lowering rates (18%).

The desire for better communications was mentioned by 8% of respondents, while reducing the number of outages and using better equipment and supplies were each mentioned by 6% of respondents.

Informing Customers of Planned Outages

The perception that Hydro One informs customers and communities when power will be turned off for scheduled maintenance and service improvements has dropped slightly since 2013. The view that Hydro One always informs them lost 11 points to 44%, while those who feel they do so usually is up 4 points to 31%, and those who say they are informed sometimes is up 2 points to 12%.

Those who feel Hydro One never informs customers about planned outages doubled to 8% since 2013.

Staff is Polite & Helpful

Two thirds of customers indicated that Hydro One Remote Communities staff is generally polite and helpful when they come to their community to do things such as bring the electricity back on (66%), down 9 points since 2013 and at its lowest level since tracking began on this question in 2009. Just 1% of customers said staff are not polite and helpful, an improvement over 2013 (2%), 2011 (5%) and 2009 (3%).

Awareness of Local Staff

Awareness of who the local Hydro One operator is steadily rising, up 8 points to 70% in this wave of research, while 30% do not know the local operator, down 7 points. Awareness is also higher than 2011 and 2009 when 59% said they knew who their local Hydro One operator was.

More than seven in ten respondents know who their meter reader is (73%), up 6 points from 2013 and at its highest level over four waves of tracking. One in three customers surveyed admitted they do not know their local meter reader (27%), down 7 points.

Environmental Protection

Fewer than two thirds of respondents said Hydro One takes environmental protection in the community seriously (63%), down 3 points since 2013. About one in ten said Hydro One does not take it seriously (9%), also down 3 points since the last wave of research. More than one quarter of respondents were unsure (28%), up 6 points.

Energy Efficiency Incentives

Asked if they are aware that Hydro One will provide them with mail-in rebates of up to $200 when they buy energy efficient appliances, three in ten said they know about this program (31%) but a majority of customers said they did not (69%).

Hydro One also operates a program called LEAP, which gives low-income residential customers up to $600 a year to help them pay their electricity bill to avoid disruptions to their service. Awareness of this program is up 6 points to 18% since 2013 but four in five respondents were not aware of the program (81%).

One in four respondents were aware that communities like theirs can generate renewable electricity through solar, wind or small hydro water projects and sell it back to Hydro One Remotes (25%), while almost three times as many were not aware of this opportunity (74%).

Hydro Rates

A majority of Hydro One Remotes customers believe their Hydro rates are either the same as the rest of Ontario (32%) or higher (40%), while one in four are unsure (24%). Just 3% of customers believe their rates are lower.

A majority of Hydro One Remotes customers are not willing to pay more for electricity generated from renewable sources such as water, solar or wind (51%), while fewer than one in five said they would be (18%). Three in ten are unsure (31%).

Communication Materials

Survey respondents were asked if they look at *Connected*, the newsletter Hydro One Remotes mails to them. More than four in ten respondents said they look at or read the newsletter (43%) and, of these (N=79), nine in ten said they find the information helpful or interesting (89%).

Internet Access & Usage

Approximately two thirds of customers said they have regular access to the internet (64%), down 5 points from 2013, while a third do not (35%).

Among those customers with regular access (N=119), two thirds think they would be likely to use the internet to get information from Hydro One such as their electricity bill and information about planned power outages (66%). This is similar to 2013 results.

One in four said they would not use the internet to access this type of information (30%) while 4% could not say whether they would or would not use it, or said it would depend.

GOALS & METHODOLOGY

Goals

On behalf of Hydro One Remote Communities, Viewpoints Research conducted telephone interviews with the utility's residential, commercial and government-supported organization customers from June 22 to August 7, 2015. Many of the questions included in this survey have been tracked from earlier customer surveys administered about every two years since 2003. The research explored the following:

- Primary and secondary sources of home heating energy,
- The incidence of specific electric appliances in homes in served by Hydro One Remotes,
- Overall satisfaction with the electricity service provided by Hydro One (tracked since 2003),
- Customers' views on the accuracy of their bills (since 2005),
- Contact with Hydro One Remote Communities and perceptions of the utility's customer service. Customers who had contacted Hydro One in the past year were asked questions evaluating this specific experience, while all customers were asked to provide their general impressions (general questions tracked since 2005),
- Initiatives Hydro One could take to improve customer service,
- Awareness of local Hydro One staff,
- Perceptions of Hydro One's commitment to environmental protection in their communities,
- Perceptions of their electricity rates relative to others in the province and their openness to paying higher rates for electricity from renewable sources,
- Awareness and use of programs or services offered by Hydro One to help customers upgrade to energy efficient appliances and provide financial assistance for low income residential customers,
- Awareness of communications by Hydro One, and whether or not customers find the information helpful or interesting, and

- Internet access and the likelihood of internet usage among customers to retrieve billing information and alerts about planned power outages.

Methodology

Sample was drawn from listed and unlisted telephone numbers in the Hydro One Remote Communities' service area. Hydro One Remote Communities has about 3,536 customers in 21 communities. This year 185 customers were interviewed, including 168 residential customers, 7 business customers and 10 government-supported organizations. The survey has an overall confidence level of ±7%, nineteen times out of twenty.

The findings of this research were cross tabulated by the following demographic and attitudinal variables:

- Community,
- Main heat source,
- Type of service (residential, commercial, government-supported organization),
- Satisfaction with electrical service,
- Whether or not customers have contacted Hydro One in the last year,
- Gender, and
- Age.

Reporting

This summary report highlights the overall views and perceptions of Hydro One Remote Communities customers. When the attitudes of a particular set of customers is statistically different from customers overall, this will be noted in the report in a bulleted point. The report also compares the findings to results from 6 previous waves of research conducted every two years since 2003.

There are significant differences of opinion among residents of the different communities served by Hydro One Remote Communities, however these results should be interpreted with caution since the number of respondents in most communities is very small. Caution should be applied, generally, when considering differences among sub-groups with fewer than 100 respondents.

SUMMARY OF RESEARCH FINDINGS

Profile of Survey Respondents

The following table summarizes the demographic attributes of all respondents participating in the research since 2003. The characteristics of customers participating in this research have generally remained consistent over time.

Table 1: **Respondent Profile**

Respondent Profile	2015	2013	2011	2009*	2007	2005	2003
Customer Type							
Home	**91%**	82%	89%	87%	81%	82%	96%
Business	**4%**	10%	5%	7%	6%	8%	2%
Government funded	**6%**	9%	6%	6%	13%	10%	2%
Age							
18 – 24 years	**7%**	8%	6%	8%	13%	10%	13%
25 – 34 years	**15%**	15%	17%	20%	26%	23%	22%
35 – 44 years	**12%**	19%	19%	21%	24%	28%	26%
45 – 54 years	**23%**	26%	21%	21%	20%	23%	21%
55 – 64 years	**22%**	16%	22%	19%	11%	10%	11%
65 years and older	**22%**	15%	15%	11%	5%	4%	7%
Gender							
Men	**54%**	50%	56%	60%	54%	56%	54%
Women	**46%**	50%	44%	40%	46%	44%	46%

Tallies may not equal 100%. Customers who were unsure are not included.

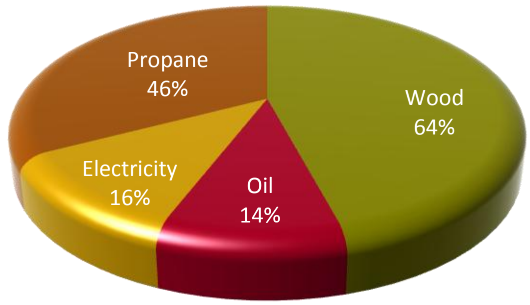
*Research conducted in 2009/2010 is reported as 2009 in this document.

Home Heating Sources

Primary Source of Heating Energy

Almost two thirds of respondents indicated they heat their homes primarily with wood (64%), while 16% heat primarily with electricity, 14% with oil and 5% use propane.

Chart 1: **Primary Source of Heating Energy**

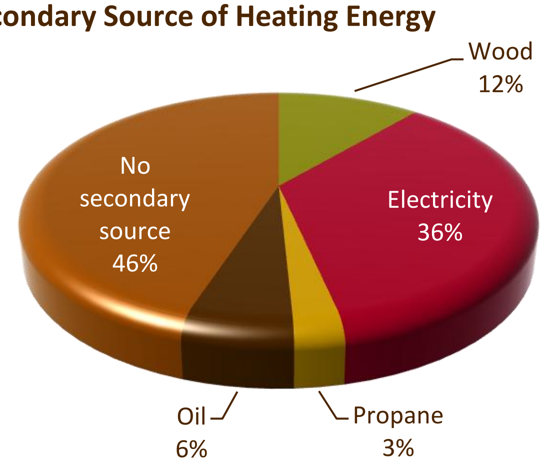


- Electricity is the primary source of heating energy in 100% of those interviewed in Hillsport/Mobert (4N). No respondents in the following communities heat primarily with electricity: Armstrong/Whitesands/Collins (3N), Bearskin Lake (9N), Fort Severn (5N), Gull Bay (9N), Lansdowne House/Neskantaga (6N), Marten Falls/Ogoki (2N), Sultan (14N), Wapekeka/Angling Lake (6N) and Webequie (7N).
- Men were more likely to say their households are heated primarily with wood (73% of 100N) than women (53% of 85N), while women were more likely to say their households are heated with electricity (20% vs. 12% men), propane (9% vs. 2% men) or oil (15% women vs. 13% men).

When asked, a majority of respondents indicated they also use a secondary source of energy to heat their homes (56%), including 36% who use electricity, 11% who use wood, 6% who mentioned oil and 3% who said propane.

More than half of respondents mentioned electricity as either their primary or secondary source of home heating energy (51%).

Chart 2: **Secondary Source of Heating Energy**

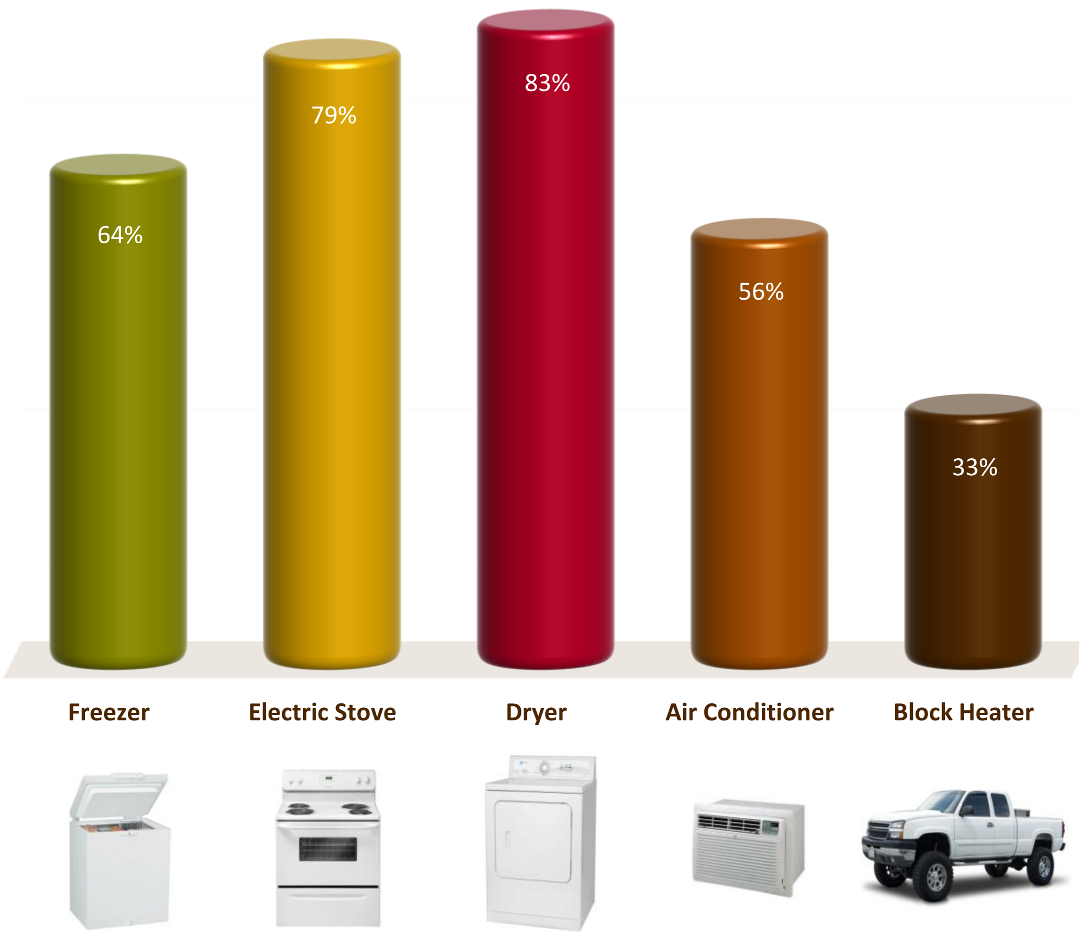


Appliances at Home

Eight in ten respondents have a clothes dryer (83%) and slightly fewer have an electric stove (79%), while 64% have a stand-alone freezer and 56% have an air conditioner.

Only one in three respondents have a block heater for their car or truck (33%).

Chart 3: **Appliances at Home**

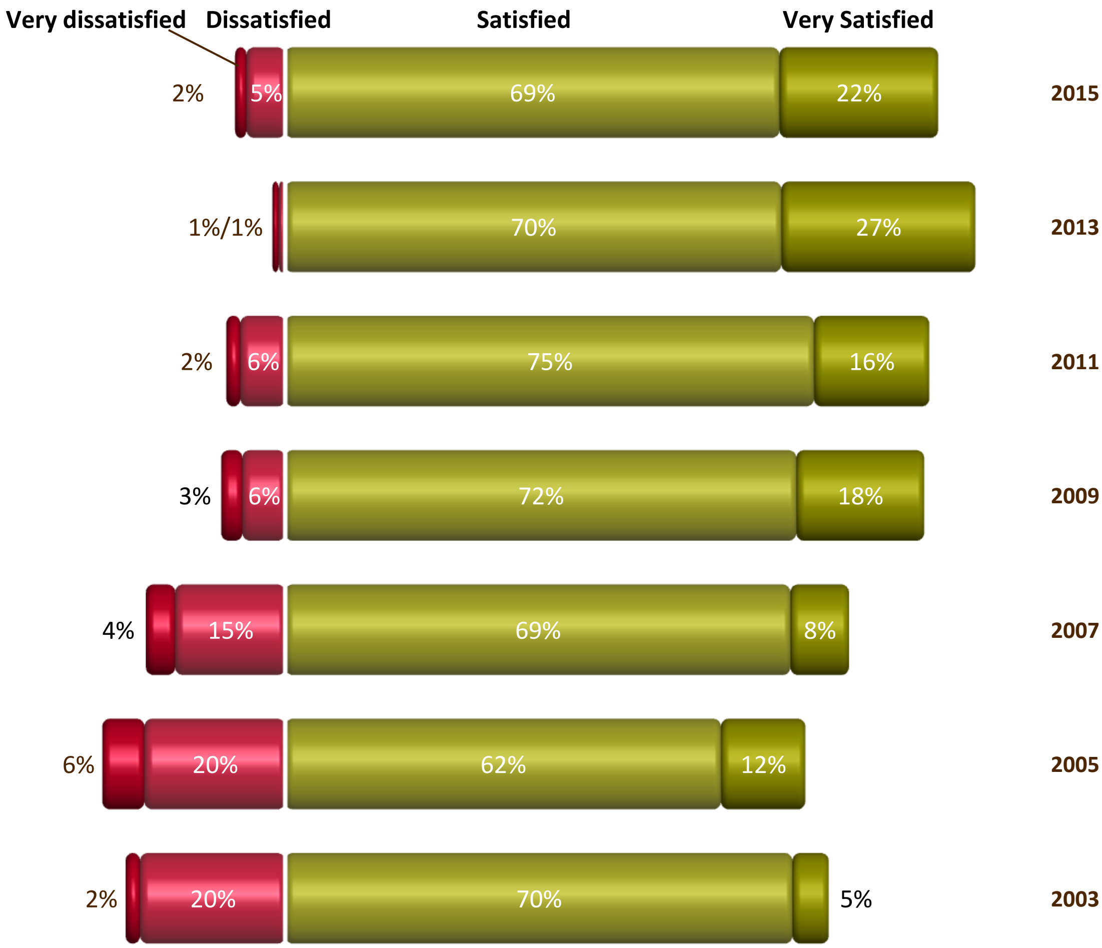


Satisfaction with Electrical Service

Satisfaction with Electrical Service

Overall satisfaction with the electrical service they receive from Hydro One Remotes, is 91%, similar to levels recorded in 2009 (91%) and 2011 (90%), but is down from 2013's high of 97%.

Chart 4: **Satisfaction with Electrical Service**



Reasons for Customer Satisfaction

Having electricity available when they want it continues to be the main driver of satisfaction with Hydro One electrical service (65%). Satisfaction with this attribute increased 11 points since 2013 (51%) and 25 points since 2009 (40%).

Approximately one in three customers attributed their satisfaction to good or improved service (20%) or improved reliability (12%). Satisfaction with customer service, generally, has held steady during this time, with one in ten customers indicating this is why they are satisfied (10%).

Table 2 shows all the reasons for satisfaction mentioned and compares this year's results to past waves of research.

Table 2: **Reasons for Customer Satisfaction**

Reasons for satisfaction	2015	2013	2011	2009	2007	2005	2003
Electricity there when needed	**65%**	51%	49%	40%	42%	43%	43%
Good/improved service	**20%**	15%	26%	18%	20%	19%	19%
Reliability has improved	**12%**	17%	25%	20%	12%	10%	10%
Fair rates	**4%**	6%	10%	5%	5%	6%	6%
Customer service	**10%**	10%	11%	13%	3%	4%	4%
Company doing the best they can	**4%**	2%	6%	5%	3%	4%	4%
Environmental practices	**0%**	1%	2%	2%	<1%	1%	1%
Rates/problems not their fault	**1%**	NA	NA	NA	NA	NA	NA
No reason/other/unsure	**12%**	19%	10%	27%	26%	26%	26%

Percentages do not total 100% because customers were permitted more than one response.

Reasons for Customer Dissatisfaction

There were 13 dissatisfied customers in this research. High rates (85%) and unreliable service (31%) were mentioned as reasons these customers are not satisfied. These reasons are consistent with those given in past waves of research.

Table 3 summarizes the reasons given by customers for their dissatisfaction over the past six waves of research.

Table 3: **Reasons for Customer Dissatisfaction**

Reasons for dissatisfaction	2015	2013	2011	2009	2007	2005	2003
Rates							
Expensive / high rates	**85%**	50%	56%	48%	64%	73%	63%
Rates discriminatory / unfair	**NA**	25%	8%	4%	9%	14%	13%
Service Issues							
Power not reliable	**31%**	50%	20%	15%	22%	21%	23%
Power quality problems, brownout / problems with appliances	**8%**	25%	4%	11%	5%	7%	21%
Other							
Don't like Hydro One	**NA**	NA	0%	5%	5%	8%	3%
Bill is confusing	**NA**	25%	0%	4%	2%	10%	8%
Community / economy hurt by service / company	**NA**	25%	0%	0%	2%	2%	2%
Bad for environment / smelly / noisy	**NA**	50%	4%	0%	0%	1%	0%
No reason / other	**23%**	NA	8%	7%	7%	6%	2%

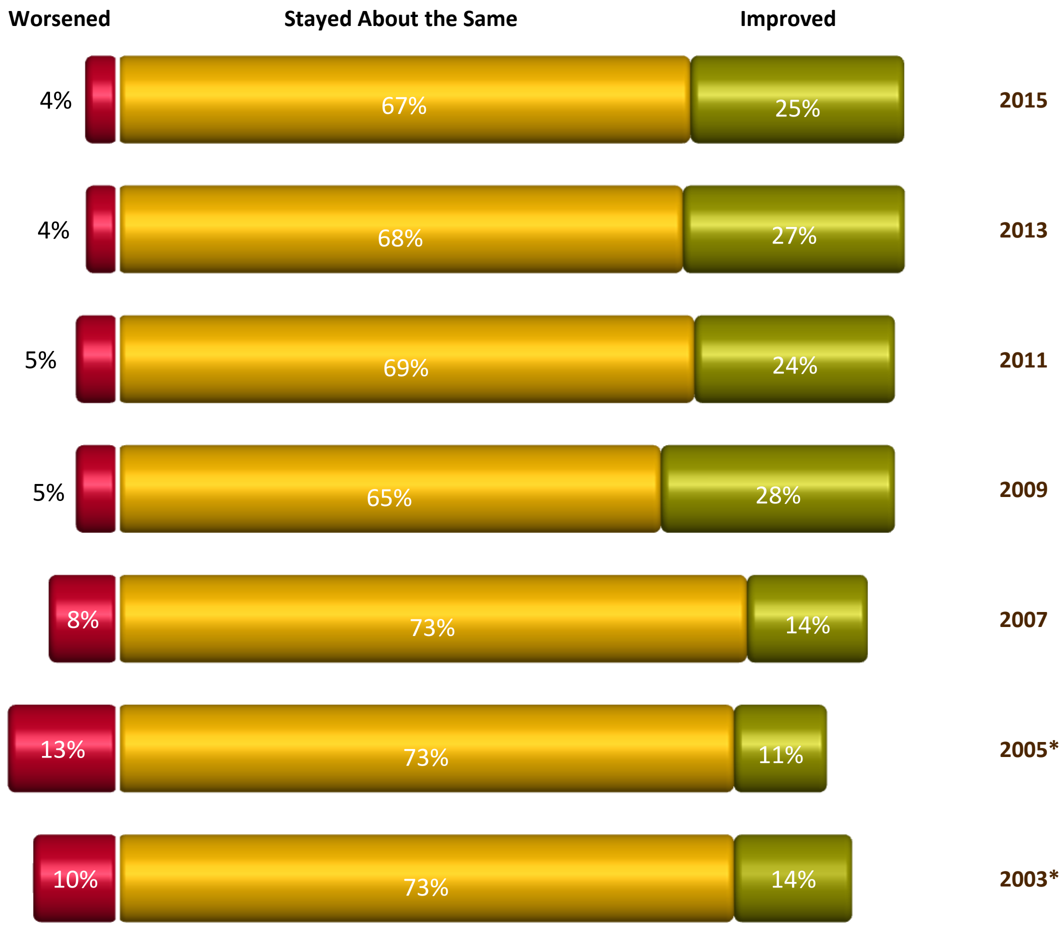
Percentages do not total 100% because customers were permitted more than one response.

Perceptions of Reliability

After remaining stable below 15% from 2003 to 2007, the proportion of customers who believe the reliability of their hydro service has improved in the past few years has remained at or above 24% since. This year, 25% said they believe reliability has improved, while two thirds of customers said it has stayed about the same (67%). Since 2009, the proportion of customers who believe it has worsened has remained consistent at approximately one in twenty (4%).

The following chart illustrates changes in customers' impressions of their electrical service since 2003.

Chart 5: **Impressions of Reliability**



*In these years respondents were given the option to say that reliability has worsened/improved somewhat or a lot. These responses have been combined on this chart.

- Those most likely to think hydro reliability has improved reside in Marten Falls/Ogoki (100% on 2N), Webequie (57% 7N) and Kingfisher Lake (57% of 7N).
- Those most likely to think hydro reliability has worsened live in Hillsport/Mobert (50% of 4N) and Fort Severn (20% of 5N).
- Men are more likely to think hydro reliability has improved (34% vs. 14% women), while women are more likely to think it has stayed about the same (75% vs. 60% men).

Bill Payment

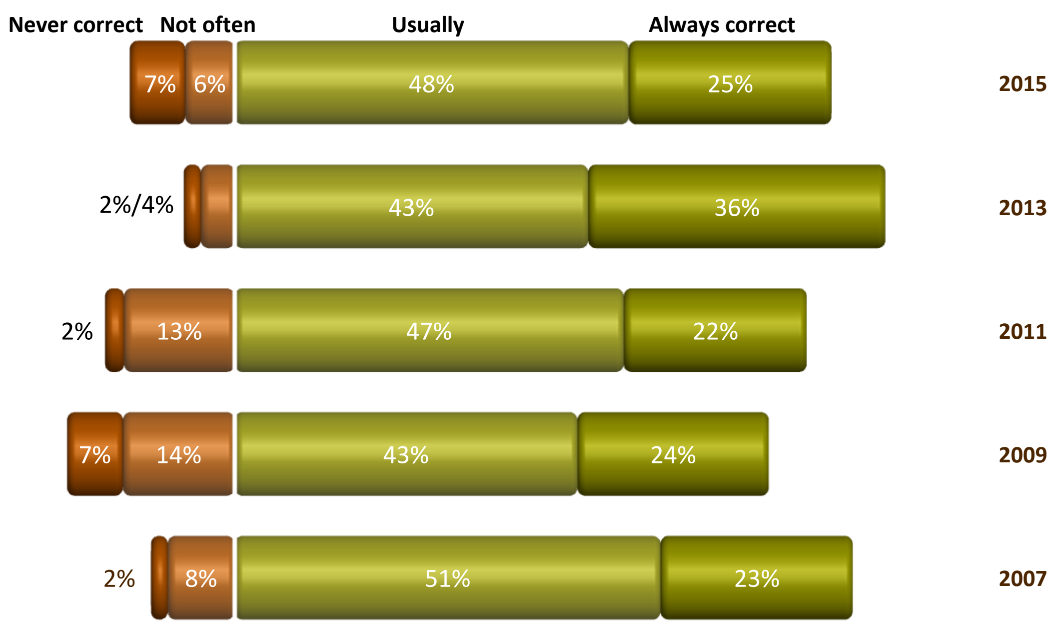
Billing Accuracy

More than 7 in 10 customers indicated they are the person who usually (67%) or sometimes (5%) pays the hydro bill.

- Responsibility for paying the Hydro bill increases with age from 38% of those 18 to 34 (39N) to 79% of those 55+ (81N).
- Those who are responsible for paying the Hydro bill are more likely to have contacted Hydro last year (78% of 77N), compared to respondents overall (67%).
- Those contacted at home are more likely to be responsible for paying the Hydro bill (70% 168N) compared to those in government-supported organizations (50% of 10N) or businesses (29% of 7N).

Among those who said they usually or sometimes pays the hydro bill (N=134), perceptions regarding the accuracy of Hydro One's billing has dropped somewhat since 2013 but is still among the highest levels recorded since 2003. In this wave 25% said their Hydro One bill is always correct, down from 36% in 2013 but higher than 2011 when it was 22%. In addition, 48% of respondents said their bill is usually correct, for a total of 73%, down 6 points over 2013 results. In total, 13% of customers said their bills were either not correct very often (6%) or never correct (7%), up 7 points over 2013 results. Consistent with previous years, 15% of respondents were unsure how to answer this question.

Chart 6: **Billing Accuracy**



- Respondents contacted at government-supported organizations are more likely to feel their hydro bill is not very often correct (43% of 7N), than respondents overall (6%).

Customer Contact

Incidence of Contact

Four in ten customers said they contacted Hydro One in the past year (42%) compared to 38% in 2013 and 44% in 2011. As in previous years, the most common reason customers contacted the utility was to discuss their bill (26%). Other reasons for contact include customers needing information (17%) or the power being out (9%).

Table 4 shows all responses to this question and compares them to those from previous waves of research.

Table 4: **Customer Contact with Hydro One**

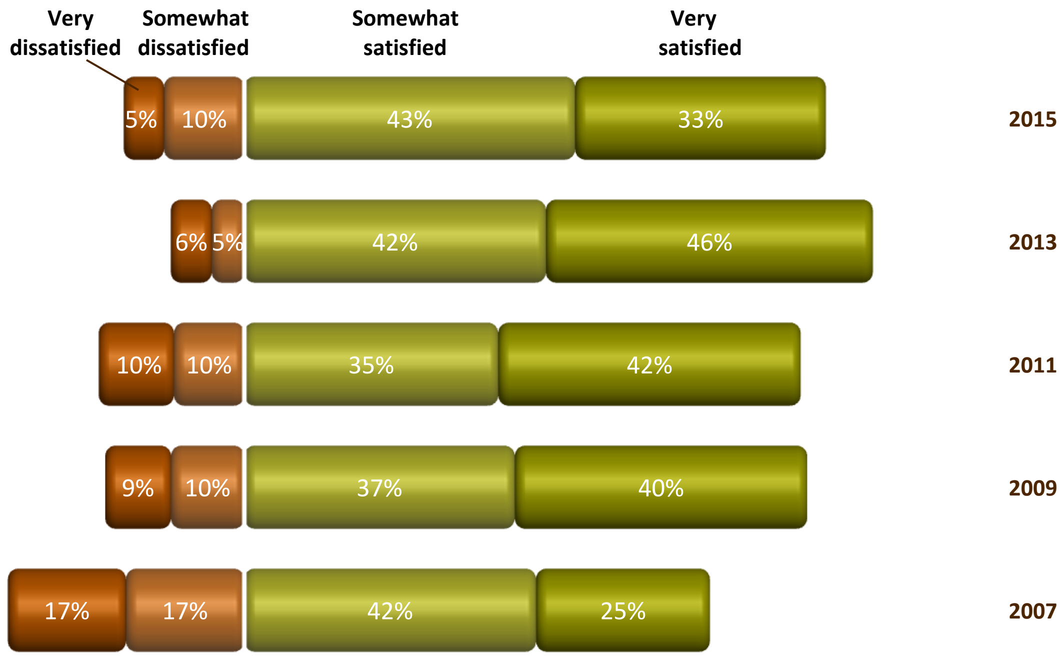
Nature of Hydro One Inquiries	2015	2013	2011	2009
About your bill	26%	19%	24%	20%
Because power was out	9%	11%	15%	15%
For information	17%	12%	13%	18%
Another reason	13%	9%	10%	9%
Have not called Hydro One in past year	58%	62%	54%	57%
Don’t recall	0%	1%	2%	2%

Percentages do not total 100% because customers were permitted more than one response

Hydro One Remotes’ Handling of Customer Contact

Customer satisfaction with how Hydro One Remotes handled their contact dropped 12 points to 76% after 2013’s record high of 88%, but is still the second highest satisfaction rating since tracking began. Those who said they were very satisfied with their contact with Hydro One is down 13 points to 33%, its lowest level since 2007 (25%).

Chart 7: **Satisfaction with Problem Resolution**



- Respondents whose primary heat source is electricity are most likely to be very satisfied with Hydro One Remotes handling of their problem (45% of 29N) and propane users are least satisfied (0% of 3N), compared to respondents overall (32%). When very satisfied and somewhat satisfied responses are combined, those who heat with wood are most satisfied (83% of 118N) and oil users are least satisfied (50% of 26N), compared to respondents overall (75%).

Factors Driving Perceptions of Hydro One & Satisfaction with Service

The research tested customers' agreement with a number of statements related to customer service, to explore customers' experiences and perceptions in key service areas. Hydro One Remote Communities scored best at **dealing with emergencies** (80% agree overall) and **staff being polite and friendly** (75%). Customers were less likely to agree that **when they call the Hydro One office someone usually answers quickly,** though a majority still agreed (62%).

Agreement with each of these statements dropped when compared to results in 2013 and, in the case of the first two statements, to their lowest levels since tracking began. Overall agreement with the third statement dropped three points to 62%, one point higher than its lowest level in 2011 (61%).

Table 5: **Perceptions in Key Service Areas**

Statement	2015	2013	2011	2009
Hydro One usually deals with emergencies, such as when as the power is out, in a reasonable amount of time.	80%* (15%)	88% (18%)	85% (20%)	86% (18%)
When I call the Hydro One office, the staff are polite and friendly to me.	75% (17%)	80% (20%)	80% (18%)	80% (20%)
When I call the Hydro One office someone usually answers the phone quickly.	62% (11%)	65% (11%)	61% (12%)	68% (12%)

*Unbracketed percentages combine agree and strongly agree responses, bracketed percentages are strongly agree responses only.

Percentages do not total 100% because those who were unsure are not included.

- The view that Hydro One staff are polite and friendly is highest in Gull Bay (100% of 9N, including 33% strongly agree) and lowest in Webequie (43% of 7N, including 14% strongly).
- This perception is also highest among those who are generally very satisfied with Hydro One Remotes (39% of 41N), compared to customers overall (17%).

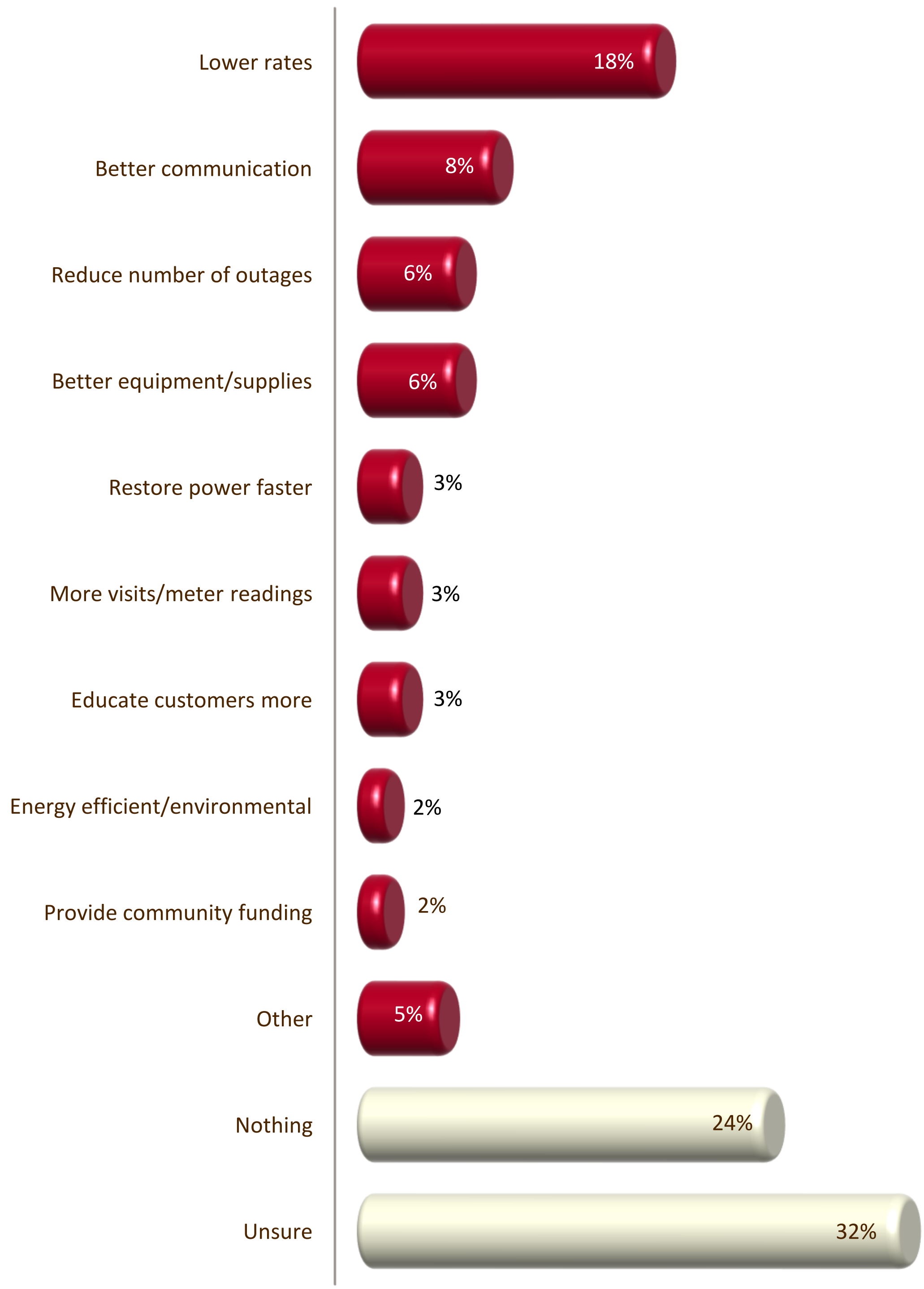
What Hydro One Can Do to Improve Service to Customers

When asked what Hydro One Remotes could be doing to improve service to customers, the most frequently mentioned improvement is lowering rates (18%).

The desire for better communications was mentioned by 8% of respondents, while reducing the number of outages and using better equipment and supplies were each mentioned by 6% of respondents.

When respondents offered an answer that could not be classified on the list of response categories provided to interviewers, their answers were recorded verbatim by the interviewer (5%). These verbatim responses can be found in Appendix A.

Chart 8: **Ways to Improve Service**

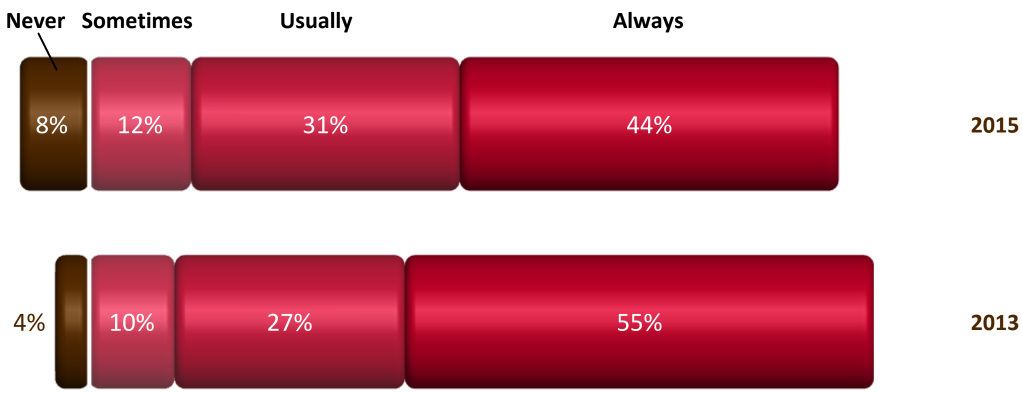


Informing Customers of Planned Outages

The perception that Hydro One informs customers and communities when power will be turned off for scheduled maintenance and service improvements has dropped slightly since 2013. Those who feel Hydro One always informs them lost 11 points to 44%, while those who feel they do so usually is up 4 points to 31%, and those who say they are informed sometimes is up 2 points to 12%.

Those who feel Hydro One never informs customers about planned outages doubled to 8% since 2013.

Chart 9: **Informing Customers**

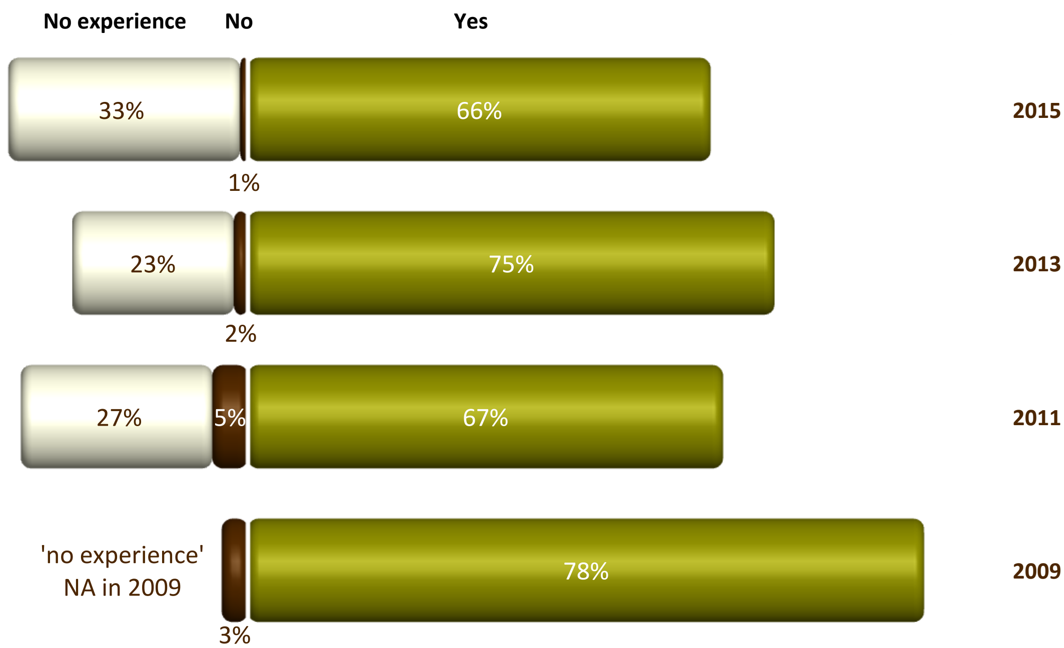


- The perception that Hydro One Remotes always lets its customers know about planned outages is highest among those whose primary heat source is electricity (52% of 29N) and lowest among propane users (10% of 10N).
- Those who are very satisfied with Hydro One Remotes generally are more likely to hold the view that Hydro One lets its customers know about planned outages (71% 41N), compared to respondents overall (44%).

Staff is Polite & Helpful

Two thirds of customers indicated that Hydro One Remote Communities staff is generally polite and helpful when they come to their community to do things such as bring the electricity back on (66%), down 9 points since 2013 and at its lowest level since tracking began on this question in 2009. Just 1% of customers said staff are not polite and helpful, an improvement over 2013 (2%), 2011 (5%) and 2009 (3%). One in three customers said they do not have enough experience to answer this question, up 10 points since 2013 and above 2011 numbers (27%).

Chart 10: **Staff Polite & Helpful**

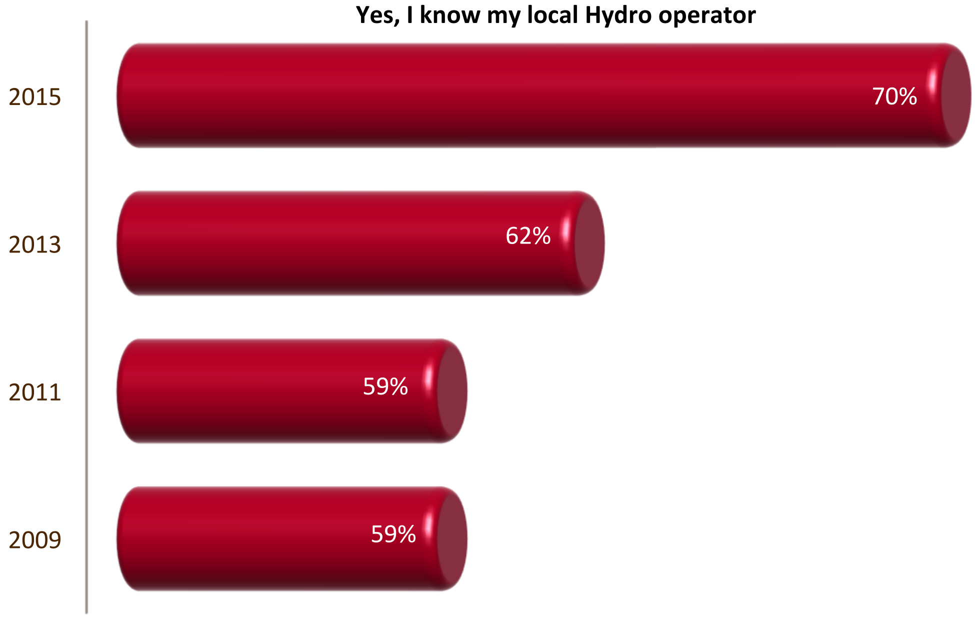


Awareness of Local Staff

Local Operators

Awareness of who the local Hydro One operator is steadily rising, up 8 points to 70% in this wave of research, while 30% do not know the local operator, down 7 points. Awareness is also higher than 2011 and 2009 when 59% said they knew who their local Hydro One operator was.

Chart 11: **Awareness of Local Operators**

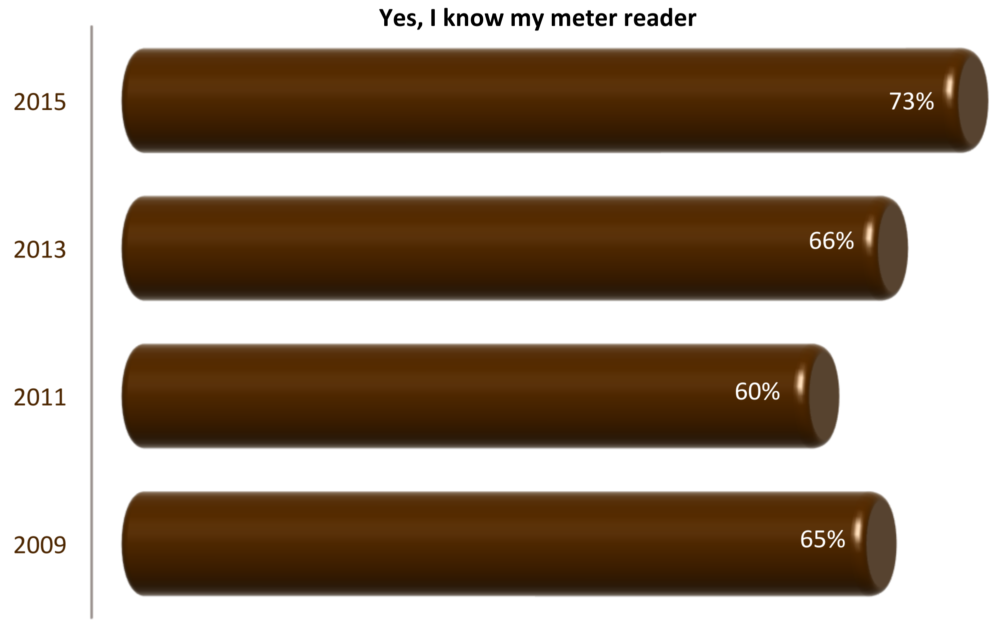


- Those most likely to know their Hydro operator live in: Bearskin Lake (9N), Kingfisher Lake (7N), Lansdowne House/Neskantaga (6N), Marten Falls/Ogoki (2N) and Wapekeke/Angling Lake (6N) (each 100%).
- Those least likely to know their Hydro operator live in: Hillsport/Mobert (0% of 4N) and Armstong/Whitesands/Colins (33% of 3N).
- Those who heat with wood are most likely to know their local Hydro operator (79% of 118N) and those who heat with propane are least likely to (40% of 10N). Those who heat primarily with electricity are less likely to know their local Hydro operator (55% of 29N) than respondents overall (70%).

Meter Readers

More than seven in ten respondents know who their meter reader is (73%), up 6 points from 2013 and at its highest level over four waves of tracking. One in three customers surveyed admitted they do not know their local meter reader (27%), down 7 points.

Chart 12: **Awareness of Hydro Meter Readers**



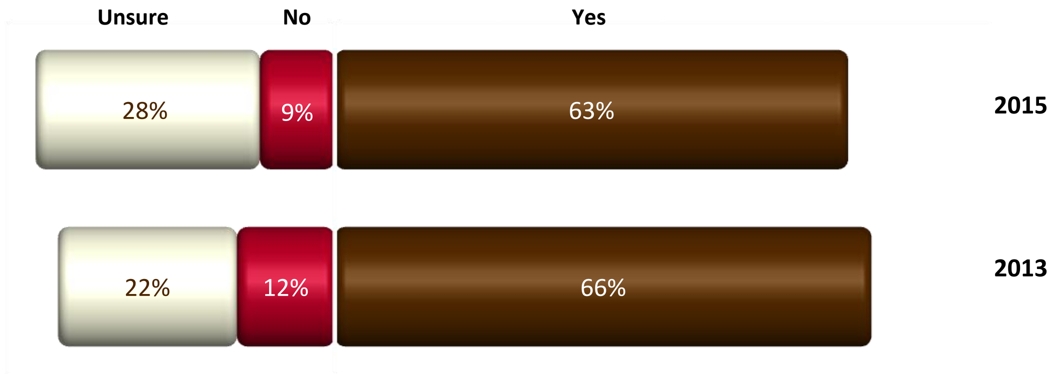
- The communities most likely to know their meter reader are Fort Severn (5N) Marten Falls/Ogoki (2N), Oba (2N), Sultan (14N) and Wapekeka/Angling Lake (6N), (all 100%).

- The communities least likely to know their meter reader are Armstrong/Whitesands/Colins (3N), Gull Bay (9N) and Hillsport/Mobert (4N), all 0%).

Environmental Protection

Fewer than two thirds of respondents said Hydro One takes environmental protection in the community seriously (63%), down 3 points since 2013. About one in ten said Hydro One does not take it seriously (9%), also down 3 points since the last wave of research. More than one quarter of respondents were unsure (28%), up 6 points.

Chart 13: **Does Hydro Take Local Environmental Protection Seriously?**

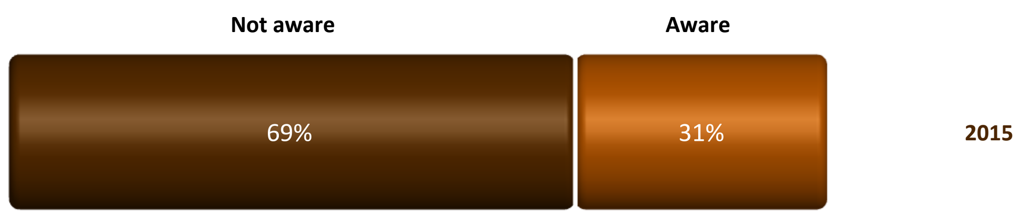


Energy Efficiency Incentives

Appliance Rebates

Asked if they are aware that Hydro One will provide them with mail-in rebates of up to $200 when they buy energy efficient appliances, three in ten said they know about this program (31%), but a majority of customers said they did not (69%).

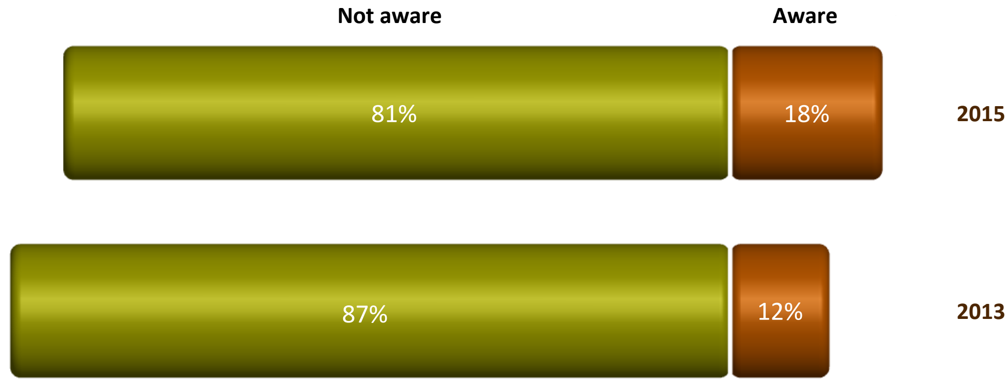
Chart 14: **Mail-In Appliance Rebates**



LEAP

Hydro One operates a program called LEAP, which gives low-income residential customers up to $600 a year to help them pay their electricity bill to avoid disruptions to their service. Awareness of this program is up 6 points to 18% since 2013. Four of five respondents were not aware of the program (81%).

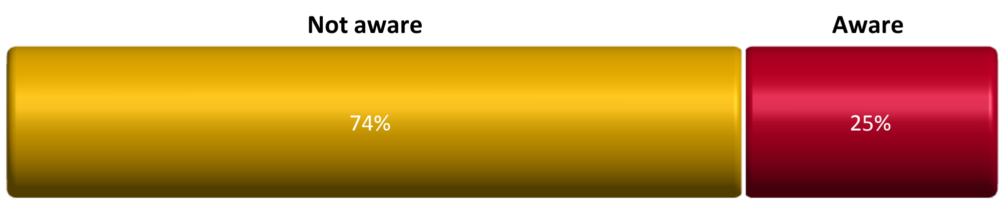
Chart 15: **LEAP Program**



Selling Electricity Back to Hydro

One in four respondents were aware that communities like theirs can generate renewable electricity through solar, wind or small hydro water projects and sell it back to Hydro One Remotes (25%), while almost three times as many were not aware of this opportunity (74%).

Chart 16: **Selling Electricity Back to Hydro**

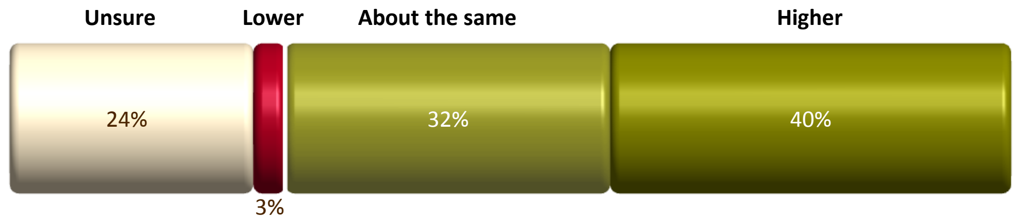


Hydro Rates

Compared to Other Ontarians

A majority of Hydro One Remotes customers believe their Hydro rates are either the same as the rest of Ontario (32%) or higher (40%), while one in four are unsure (24%). Just 3% of customers believe their rates are lower.

Chart 17: **Hydro Rates Compared to Other Ontarians**

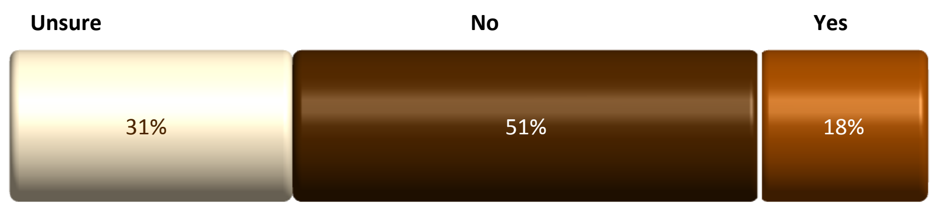


- Residents who are very satisfied are less likely to think their rates are higher than the rest of Ontario (20% of 41N), compared to respondents overall (40%).

Willing to Pay More?

A majority of Hydro One Remotes customers are not willing to pay more for electricity generated from renewable sources such as water, solar or wind (51%), while fewer than one in five said they would be (18%). Three in ten are unsure (31%).

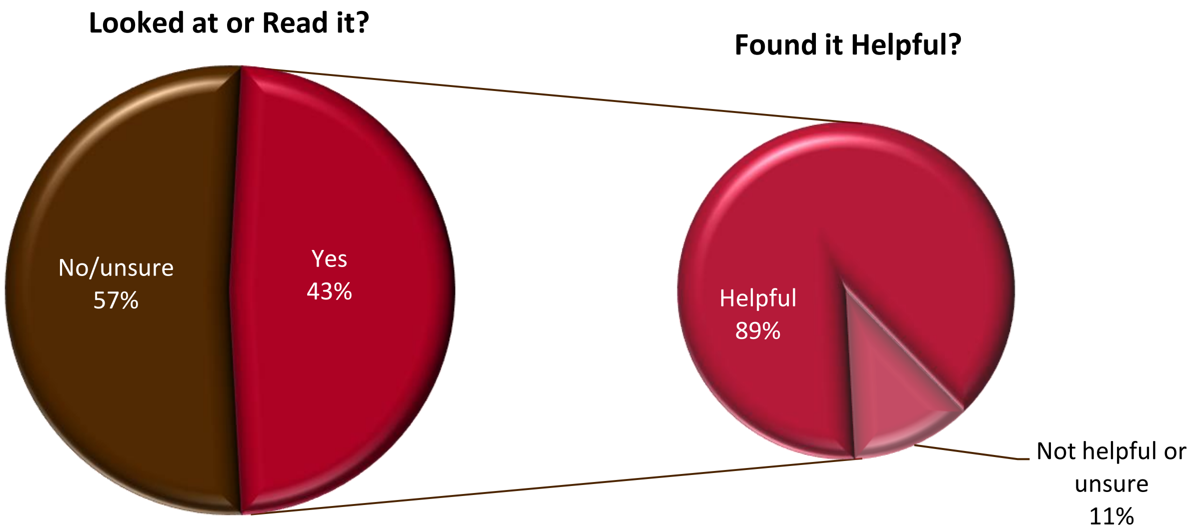
Chart 18: **Willing to Pay More?**



Communication Materials

Survey respondents were asked if they look at *Connected*, the newsletter Hydro One Remotes mails to them. More than four in ten respondents said they look at or read the newsletter (43%) and, of these (N=79), nine in ten said they find the information helpful or interesting (89%).

Chart 19: ***Connected*, Newsletter from Hydro One Remotes**



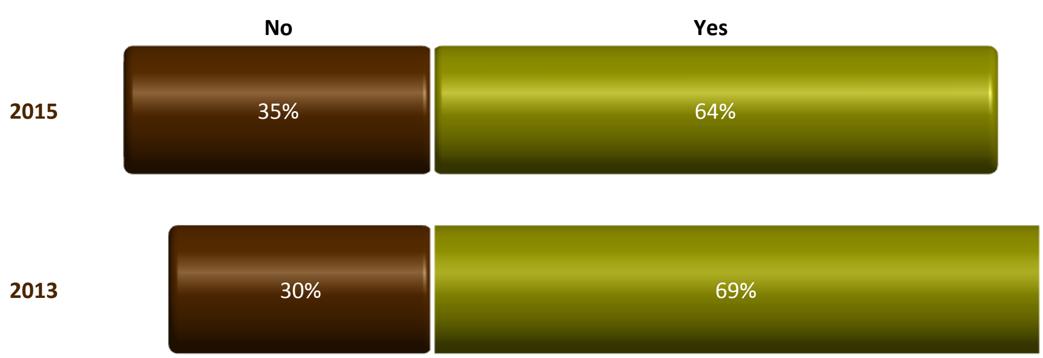
- Residents who had contacted Hydro One Remotes in the past year are more likely to find the newsletter helpful or interesting (100% of 38N), compared to those who did not contact Hydro One (78% of 41N).

Internet Access & Usage

Internet Access

Approximately two thirds of customers said they have regular access to the internet (64%), down 5 points from 2013, while a third do not (35%).

Chart 20: **Internet Access**



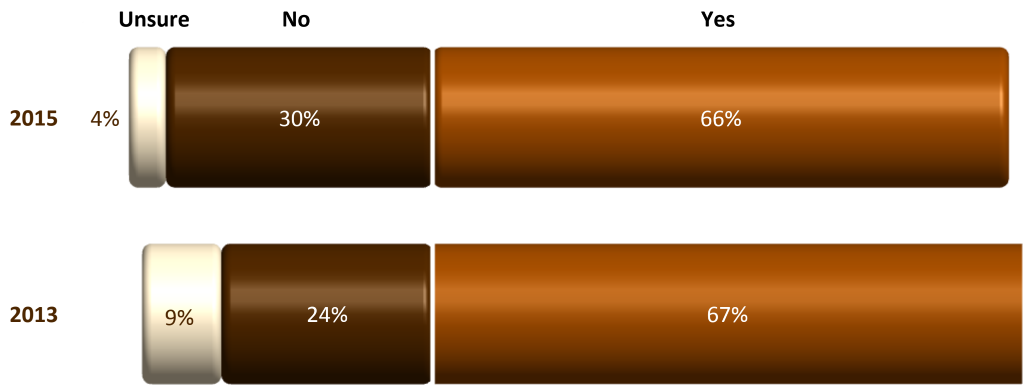
- Internet access is more than twice as high among 18 to 34 year olds (92% of 39N) than those 55+ (44% of 81N).

Internet Usage

Among those customers with regular access (N=119), two thirds think they would be likely to use the internet to get information from Hydro One such as their electricity bill and information about planned power outages (66%). This is similar to 2013 results.

One in four said they would not use the internet to access this type of information (30%) while 4% could not say whether they would or would not use it or said it would depend.

Chart 21: **Internet Usage**



- Businesses (100% of 5N) and those who contacted Hydro One Remotes in the past year (80% of 50N) are more likely to use the internet to get information from Hydro One Remotes, compared to customers overall (66%).

APPENDIX A

Q26 What are the most important things that Hydro One Remotes, the company that provides you with electricity, should be doing to improve service to you?

Community	Ways to Improve Service
Armstrong/ Whitesands/Colins	Seasonal rates are too high.
Bearskin Lake	Continue advertising their advice to save hydro. Give energy conservation stuff like light bulbs.
Big Trout Lake/KI	Send surveys to the customers of First Nations. Make themselves visible in the community. The generator we have is at full capacity. It would be good if they could work on that. Have fewer power outages. It seems as if, every time they come out to our community when the power goes out, we notice an increase in our hydro bill the next billing cycle, and in the winter it's ridiculously high.
Biscotasing	Send out the papers about rebates. Stop the power outages. Increase reliability. Move from the diesel generators and pursue the alternative energy sources including nuclear power generating stations. When a brownout occurs, it would be helpful for them to explain why it happened. It would also be helpful to have some information about surges during brownout for the telephone and fridge. Improve communications by phone and cell phone. Put in bigger diesels. There are always power outages on long weekends. Sometimes the letters don't correspond with the situation we have here. Fix problems instead of using bandaid solutions.

Community	Ways to Improve Service
Deer Lake	Get my new house hooked up. I have been waiting 3 years. Keep the power on. Keep it going. Fewer outages. There are too many bushes around the hydro poles and wires. Make another dam. Hook up my new house. It was built 4 or 5 years ago and I still have not been hooked up to hydro.
Fort Severn	Provide more and proper installment of lights and wiring and a program that will lower the rates. We need accurate, honest meter readers and we should be informed what our meter readings are. We are never informed by the meter reader. Give more information sessions and promotional giveaways so we can get more information. Not everyone reads the pamphlets in the mail. It's just like another flyer.
Gull Bay	We like to be informed of planned outages. The hydro operator will turn off the power suddenly without notice. We don't know why. Sometimes it will be off about 5 minutes.
Hillsport / Mobert	Read the meter the monthly Come down here and let us know what is going on, and what we can do to improve our electricity costs and bring down the bill. They are never helpful.

Community	Ways to Improve Service
Kasabonika Lake/ Kasabonika	Generate more power. There is not enough power in the community. When they put the Christmas lights out we get a blackout. Continue maintaining the power and doing what needs to be done. Upgrade the power. Have seasonal decreased rates in winter time. More of the executives should make long-term trips to these areas. I don't think you know how people live in this community. There has to be more exposure to these lifestyles, and that goes for any business selling services in these areas.
Kingfisher Lake	Bring a transmission line in instead of a generator. Give discounts in remote communities. Provide more information how to save power.
Lansdowne House/Neskantaga	Be more efficient so I don't live in darkness for even one hour.
Marten Falls / Ogoki	Make the power better with fewer outages.
Sachigo Lake	Provide lower rates especially during the winter. Participate in the grid plan and help First Nations with the distribution of the power throughout the community. Keep notifying us with all the information. Provide more selection as to what comes into the house. Have an option for underground or overhanging lines.

Community	Ways to Improve Service
Sultan	We need new hydro poles in town. They were supposed to raise the wires up and they never did. I don't believe the debt retirement should be on our bill. Provide this information properly. Notification of scheduled power outages should be advertised better. It affects sump pumps. The time of year that they choose to do the outages we had high waters and they almost flooded my basement. The outage wasn't advertised. Get rid of the debt retirement charge and continue the 10% rebate. Have someone come in to check the wiring. It would be nice to have an online bill. Our whole town has to be rewired. It's all 110 wire, and needs to be on 220. It's not sufficient for the winter. You lose a lot of your power between the amp and the house. If they had heavier wire in the towers our bills wouldn't be as high.
Sandy Lake	Make sure that there's no outages. Talk to customers more often. There are a lot of problems with the birds. Crows land on the poles and wires. They get electrocuted and knock out the power. Have different options available for hooking up to the grid; or a way you can do it directly and not have to go through the Band. If you're not on the list of those scheduled to receive help you don't get hooked up. It would be great if there was a way you could do it yourself. I use telephone banking and Hydro One doesn't have that. Upgrade the boxes and wire and hydro lines. This is an old house and the plastic is chipping off the line. The meter guy said that's quite a hazard. The electrical inside the switches need to be upgraded in the old houses. They should not increase the hydro rates because we live in a remote community where everything already costs so much. We barely get by as it is. It does hurt a lot of families when they get disconnected a lot. Put increase notices in the newsletter.

Community	Ways to Improve Service
Sandy Lake *cont'd*	The generator is growing weaker and weaker as more houses get hooked up. Improve the situation so we have service without interruptions e.g. at Christmas time. Make sure they always let us know at least one day before, if possible, about power outages. Figure out an alternative ways of getting power here. Diesel generated power is too much. Try a dam that won't affect the river too much. Find out more about geothermal heating. They should hook us up to the provincial grid. We are fly-in reserve. There's no way to get fuel in except by airplanes and it would certainly benefit people to hook us up to the power grid. We, as residents, end up paying for the costs of the service as well as the high rates, which is why our bills are so high. Maybe twice a year, they force community members to pay up their bills in full or they come into our reserve and cut off people's service. They are not nice people. They just go and do what they want. They come into people's yards and cut them off. The ones that get cut off are the ones who can't afford the high prices. They practically force a gun down our throats and force us. We have no choice. This past February and March we got notice that they were going to come and disconnect houses and this was in the middle of winter. We had a hard winter and they're telling us they're coming here to disconnect houses! I think that's wrong! When the power goes off it affects our school here. We lose our school days. We lose out on school instructional days. It takes a while for Hydro to heat up the big building, it affects the kids and their families. There should be some kind of reward program for us in the fly-in reserve, rebated with some kind of credit towards our bills. I think Hydro One has a monopoly over us. They don't even reward us. Provide some kind of benefit program for paying our hydro bills on time. That would make people pay their bills on time more likely, if they thought they would get some kind of reward. Last year I got a big bill, about $3000, then the next month my bill was down to $600. I called Hydro One and they said they were in the middle of transferring from an old computer system to a new computer system. I wonder what else is fishy about their billing practices. My daughter collects welfare and her bill was about $400 and all of a sudden her bill went up to $3000.

Community	Ways to Improve Service
Wapekeka/Angling Lake	Have a newsletter or meetings sometimes. Get the power back on faster.
Webequie	If they come into the community again they should notify the household that they’re going to disconnect, because sometimes we have our payments on hand when they're coming into the community. Check the hydro lines. Sometimes they can come down in between the hydro poles. Sometimes they hang across the road. They should have a backup system on the airport strip, in case there's an emergency. What if someone gets sick and power is off. Come to the community more often, instead of just when there is an emergency. If they are coming to disconnect they should let the house owner know. Support road access for remote First Nation communities, if and when the government decides to put it in.

Appendix E: 2016 Customer Workshop Presentation

Hydro One Remote Communities Workshop

Summary of Discussion

November 23-24, 2016

Sioux Lookout, ON Sunset Inn

Workshop Objective: To provide an open discussion between HORCI served First Nations, HORCI, OEB and INAC in order to plan for connection and improve coordination, communication and community relations.

Participants:

Sachigo Lake First Nation	Kingfisher Lake First Nation
Bearskin Lake First Nation	Weagamow Lake First Nation
Big Trout Lake First Nation	Wunnumin Lake First Nation
Kasabonika Lake First Nation	Wapekeka First Nation

Regrets due to weather: Sandy Lake First Nation, Deer Lake First Nation

Mandy Wirta, INAC
Richard Habinski, Breann Brunton, Windigo
Donna Brunton, Laura Sayers, Shibogama
Franz Seibel, Roopa Rackshit, KO
Richard Chukra, IFNA
Karemer Coulter, Una O'Reiley, Kevin Mann, Ralph, HORCI
OEB

November 23, 2016 AGENDA

- Wataynikaneyap Project update
- Local Distribution Companies preparing for connection to transmission
- INAC presentation and discussion
- Hydro One Remote Communities Inc.
  Transmission readiness, connections and construction, joint use, safety, community relations, customer service, collections, rates, regulatory challenges, asset management, upgrading process, reindeer, retrofit and conservation programs, etc.

Discussion Themes

1. Backup Generation
2. Environment
3. Affordability, Billing, Rates and Customer Service
4. Housing Connections

5. Safety and Emergency Response
6. Community Relations
7. Access to Conservation and Renewable Programs

1. Backup Generation

Community jobs with be affected including contractors and generator operators. There is a concern regarding the reliability of the transmission line. Some buildings have backup generation, but many homes do not have generators. There is value in the generators that the First Nations own. It is difficult to maintain generators if they are not used for some time. Some are old or in disrepair and should not be kept. Any unused equipment and storage tanks should be removed.

Recommendation: Continue to work together to establish a plan that works for HORCI, INAC and FNs for backup generation. Evaluate the backup generation requirements in each First Nation including which buildings have backup generators. Any new construction of essential service infrastructure needs to include backup generation (school, clinic, water plant).

2. Environment

Sound pollution is an issue from the DGS. There is contamination at the fuel farm and also at sites where backup generators and fuel tanks were stored. Remotes audits and tracks improvements in emissions and contaminants. Remotes burns approximately 17 million liters of fuel each year. Clothes hung outside smell from the generator smoke. Used oil is removed from oil changes. Are old barrels or single walled tanks removed? Is there a plan to remediate DGS sites? Environment is very important to First Nations.

Recommendation: Develop an environmental plan with the First Nations that includes current HORCI indicators and include any First Nation indicators. Provide annual reporting to the First Nations in order to monitor environmental indicators.

3. Affordability, Billing and Customer Service

Disconnection policies and communication needs to be improved. LEAP and OESP need to be more accessible. There is lots of paperwork that ONWAA can assist with, but many applications are still not processed. Coordination with Ontario Works is essential to reducing the number of disconnections. How will the rates change after transmission? Customer service should be available in OjiCree. There should be a Remote Northern First Nation rate as the costs in remote First Nations are uniquely high. Interest rates on late payments should be reduced. Funding a First Nation liaison would reduce disconnections and late payments.

Recommendation: Develop Customer Service policy that includes wages for a liaison in the First Nation, create a remote rate, improve accessibility to rebates, improve disconnection communication, include First Nation customers on customer service review committee.

4. OEB Priority Setting

The OEB is asking utilities to work with customers to ensure that the utilities take into account customer priorities in business and investment planning. This discussion is an opportunity to understand what is important. Each participant was given $10 bills to "vote" for what is most important in various areas of Remotes' work program.

Community Relations	18
Affordability	17
Customer Service	17
Renewable Energy	18
Safety	11
Reliability	14
Environmental Protection	26

Discussion notes:

Environmental Protection: My grandfather taught me to protect the land as part of my religion and cannot be compromised.

Renewable Energy: Climate change is real. Makes sense to get our energy and other needs from the earth.

Community Relations and Customer Service: HORCI needs to understand what its customers want and their reality. Customer Relations and Customer Service are HORCI's weaknesses. Hydro One is strong technically but its management of its customer base is weak. You aren't in the community. You need to work in partnership with the community.

Electricity is not affordable. People can't afford it.

5. Housing Connections

HORCI requires an ESA inspection prior to connection. There is only one ESA inspector for remotes and there are often delays. In order to connect a building, HORCI must complete a housing layout, contractors cannot complete the layout or complete any work for HORCI due to the union. Fees are established based on established rates. Fees can be reduced if work is bundled. ESA may approve a house before its finished and the house can be connected before it is completed in order to provide electricity during construction. In this way power tools and heaters can be run from the house electricity. It is unclear what HORCI's role is regarding electricity between the meter and the DGS. There should be more options for electrical technicians on reserve.

Communication with HORCI can reduce costs of design and installation especially for positioning of the building and mast, subdivisions and community planning. Retrofit programs are available including LED street light retrofit and conservation programs. LDCs require regular maintenance and need to be kept safe. Colocation of internet cables on poles requires a HORCI engineered design. Annual colocation fees are not charged. Cash in full up front is difficult for First Nation cash flow. 50% cash would make things easier with funding. Will the location of transmission connection be at the DGS site?

Recommendation: Improved communication between HORCI and First Nation infrastructure planning. HORCI to attend housing and public works conferences to improve understanding and communication with HORCI on housing construction and permits. Reduce HORCI layout and engineering fees. Hire more ESA inspectors.

6. Safety and Emergency Response

HORCI operators are trained in house fire disconnection. Heavy equipment operators are not aware of electricity dangers if they hit lines. There is a handbook for emergency responders on how to deal with electricity emergencies. Firefighters and emergency responders and heavy equipment operators need training to deal with electricity emergencies. School visits are available.

Recommendation: HORCI to provide training in electrical safety at regional conferences. First Nations to invite remote First Nations to provide safety awareness and complete school visits.

7. Community Relations

HORCI staff housing used to be available as hotel overflow for visitors. Can people stay at the staff house? Does HORCI also rent houses or hotel rooms? HORCI provides training for apprentices at confederation college for linesman. HORCI is unionized and hiring follows the union process. What is the status of HORCI service contracts? Is it possible to sell HORCI generators and other equipment when transmission is connected? HORCI will need to prepare to serve seven IPA First Nations by hiring more staff. The disconnection list is sent every month even though disconnections are only twice per year. This improves communication and helps the band to work with customers.

The chief and council have been handling disconnections. It is a big job for council to manage however, the council is able to care for people and need to approve a visit from HORCI. A community liaison position would provide wages for someone to help people with programs, billing, safety and many other aspects of HORCI relations. There are some programs available with HORCI to support community activities, this helps with relations. A good partnership is required in order to deal with restrictions, disconnections, environment and community infrastructure development. Electricity is a treaty right due to the fact that essential services (health, shelter, education, water) require electricity.

Recommendation: Develop a Community Relations and Engagement Policy that includes HORCI and First Nation roles and responsibilities. Schedule regular communication and engagement visits. Fund a community position to coordinate training, safety, billing, community relations, promoting conservation, etc.

8. **Access to Conservation and Renewable Programs**

First Nations are developing renewable infrastructure that needs to be supported by HORCI. Other innovative opportunities needs to be considered as well including heat recovery furnace at garage, furnaces that burn used oil and geothermal. First Nations need HORCI to improve its process and partnership for renewables and the Reindeer program. Retrofit, streetlights and other programs need to be more accessible and promoted in the community. Housing retrofits are still the best way to improve efficiency and conservation. Overcrowding makes conservation difficult.

Recommendation: More engagement when designing conservation and renewable programs so that they are accessible, meaningful and used.

November 24, 2016 AGENDA

- OEB Presentation on remote residential rates
- Break out Discussions

Discussion Themes

- Reduce Standard A Rates
- Eliminate transmission delivery charge
- Secure RRRP
- Improve accessibility to rebates
- Create a separate Northern Remote First Nation Rate
- Reduce late payment interest rate
- Improve REINDEER rate
- First Nation cost of living and electricity as a treaty and human right
- Coordination between INAC, HORCI and OEB

Group 1 Feedback

- **Drop Standard A rates for remotes:** The current Standard A rate is 97 Cents/kWh for all the Government funded buildings and with grid connection it will drop to 29 Cents/kWh. It was suggested to consider implementing the 29 Cents/kWh now for a smooth transition to grid connections. OEB could help subsidize that.
- **Drop delivery charges:** Delivery charge was for the grid connected communities in the south that they wanted gone. To consider getting rid of monthly charge on bills for the northern First Nations.
- **Subsidies:** To be cautious on the subsidies during discussions with INAC and to ensure that they need to maintain the current Standard A rate subsidy until the grid connection. Funding cannot be reduced or stalled/when they see cost-savings. (When formulas are calculated for operations and maintenance, the Standard A rates are included and built into the subsidy electric component)
- **Other subsidies:** Construction costs for connections (poles etc) are much higher in the North than in the South.
- **Breakdown of the bundle rate:** The true cost of the power for North is to be provided towards customer education. The breakdown will facilitate better understanding of revenue sources, and payments made on specific allocations by home owners. Even though community members pay a subsidized cost, the breakdown could serve the purpose of an educational tool for RRRP and residential rate payers.
- **Customer relations and Customer service**: To enhance, the group suggested to tie into processes and structures through local RRRP workers who are closer to the communities and delivers energy programs. To initiate a customer education process on rates, bills etc, as part of customer education-a community-based approach. The conservation program could also be brought back as a behavioral modification on using less power,

on using technologies that reduces consumption, bills. (H1RC have an application-based…appliance program)

- H1RC in partnership with the community could engage with the rate payers on conservation, consumer education programs besides the bill collections. **More presence:** HORCI and OEB are asked to have more presence in the community.
- **Late payment charge**: 19.5% on an annual basis is too high and the time frame that kicks in is too short with 20 days. To consider with 60 days' time frame and to be tied to borrowing rates/user rate fees and not market-based rates.
- **Application based programs:** Special consideration is to be made for seniors and elders who find it difficult to navigate through the application process. Try to build/tie into some of the activities showed in the bill and maybe make them "automatic" rather than applying for them.
- **Include an "adder" to off-grid renewable projects:** REINDER programs are not enough, there need to be an "adder" to the REINDEER rate, as an incentive. The "adder" should consider the impact of reduction of the standard A rate. The renewable projects could be made more attractive to find capital/funding for the remotes.
- **Community-specific concerns:**
  KIFN: Senior complexes-individual apartments owned by seniors get Hydro bills but there is no funding for common areas.
  Bearskin: 20$% rebate across the board, on everybody's' bills -suggested directing the savings towards employment, childcare, education, lands and resources, restaurant etc.

Group 2- Feedback on the OEB processes

- **Electricity rates:** Hydro bill are too high. To consider seasonal rates as lot more electricity is used in the winter. Or, people who don't have woodstoves have higher costs, especially for the elders and seniors. There are cases with high bills and no jobs. To consider percentage reduction of energy bills.
- **Subsidies:** All customers are different. Some have trucked water, and require lots of electricity to run pumps, so, it is not one size fits all when considering subsidies.
- **Power, food, health:** Anecdotal references were made to situations when options is not food versus power with both being essential necessities. Junk food is cheaper which leads to health and medical treatment issues that is cost intensive. Profile of a different family sizes can be acquired from community economic development offices to iron out fairness in payments. Single mothers, grandparents caring for grandchildren, mentally-challenged, and disabled patients who are unable/or shy away from the welfare application process, become dependents on regular families stretching family budgets. There are no resources to bridge the application process.
- **Incentives**: Incentives for reduced energy use.

- **North versus South unfounded perspectives:** Decision-makers from the South have to visit the northern communities to see first-hand, ground realities. The communities in the north have to deal with a lot more situations that the south doesn't face. Also, "Thunder Bay is not north or reflective of the TRUE NORTH". Also, get an understanding of family structures and community way of life.
- **Energy Star Program**: To be made available to everyone and not just for low-income group people. The H1RC program swaps old appliances for Energy Star appliances.
- **Feedback on the H1RC processes**
- **Community relations**-To understand community' expectation on building relations- "H1RC version is different from ours". Mostly council members attend meetings in Thunder Bay and sometimes the information flow is restricted or stalls at that level. Suggestion was made to engage with the communities more through community meetings organized for EVERYONE to attend, open houses, FB, radio etc. Also, forward materials that are easily understood by the community. Sending program promotional/marketing pamphlets with bills doesn't always work.

  People who implement programs like OESP and LEAP need to go to communities, help them with the application process.
- **Housing:** Lack of housing leads to overcrowding that lead to high electricity bills. Eg: North Caribou. Also, with large families, it is very easy to go over the first 1000kwh threshold. To consider up to 2000 kwh. - 89 $ rate should go higher (upto 2000 kwh)
- **Renewable projects:** Community is interested to invest**,** own and run more renewable options.
- **Standard A** rate on band council building and assets needs to be lower. Shouldn't have to wait for grid connection to get lower standard "A" rate. Don't want rates to change or access to RRRP to go away when grid comes in. Need more than just the $20 service charge off and not make it comparable to the delivery charges of the south.
- **Joint process**: Consult with INAC for cost savings on when the grid comes in. And ensuring that any subsidies that come from OEB does not reflect on a reduced cost saving options from INAC.
- **Subsidies**: Should not be something we have to apply for.

  Additional concerns:

  Lots of power surges with diesel generation or power goes out for a few seconds. Thus, outages should result in lower bills and should be reflected on the bills.

  Sometimes when they come to communities to do the disconnections, they won't take any cash.

  Disconnect charges add an extra burden and are varying from 65-165 that ensues a long wait to be reconnected once the bill is paid.

Group 3 Feedback

- **Standard A rate:** There are two rates-one for the First Nations and one for the Municipal. So, the community deals with the individual bills and Municipal/Band type accounts. Rates are high that the Band office have to sometimes pay from other programs. It was suggested that the respective community band offices need to be made aware that with the grid connections, there is a possibility of the reduced/stalling of the INAC funding and subsequent subsidies. This needs clear understanding amongst all of us and we should be on the same page.
- **Understanding realities:** Both, the communities and H1RC want to be treated fairly and so, to approach the system through a holistic lens. There are realities on both sides-to acknowledge and respect. Adding or subtracting services without realizing the ground realities leads to misunderstanding and lack of expectations.
- **Time of Use rates:** Do not want time of use rates as there are unemployed people and energy consumptions to consider. Using the time of use rate will only hurt us.
- **Cost of living:** To take into account the cost of living and all costs including freight as they are significantly higher. Everything costs double in remote Northern Stores even with a subsidized rate.
  Need to help seniors and Elders who cannot keep up with the costs of living. Reference was made of the 700+ OSEP applications that are stuck in the systems process. This is not acceptable when community members rely on these programs. OEB could address the issue with the Ministry of Finance.
  Also single parents, some are too young to apply and get into the system. Grandparents are playing the roles of the parents and have extended responsibilities.
  Welfare is $400/month/person. How much can it be stretched to in a typical size family?
  Need to keep **"entrench"** RRRP and Standard A subsidies on a long-term basis irrespective of change in Governments. To ask the Province to approach INAC.
  Rates cannot go up (increase) with connection to the Provincial grid. If that happens then there is no value in being connected to grid. We cannot burden communities with additional payments-a principal used for guidance with grid connecting.
- **Customer Services:** Place someone in our community that can help with applications/Forms. Also, need help within the communities with arrear management and not just a 1-800 number. To include management of bills.. when trying to decide how to pay all bills-food, fuel or electricity.
  Reliability is a problem ..need someone in the community to keep the lights on. To explore solutions, H1RC need to visit the communities and talk to community members. Or the community can set a program and appoint someone in the community in partnership with H1RC. The group stressed on **education and communication**.
  Reference was made of initiating financial management skills.
  The group echoed that we are "remote" and have unique set of challenges. All FNs cannot be treated the same. Comparisons between the North and South should not be made. Reference was made with Land-Fill sites as an example.

- **Renewable Energy:** Walk hand in hand in renewable projects.
- **Watay Power:** To have discussions on bills and payments post grid connection. It is important to prepare the community.
- **Conservation:** Stressed on H1RC conservation programs, appliances and light bulbs replacement etc.
  Payments: Payments upfront
- **Back up generation**: A must for any catastrophe for basic services. No compromise on that. To consider portable units by H1RC. It is not only a back-up system, there are financial implications too.
- Quick response time, especially in the winter-someone on standby 24/7. Faster service.

Appendix F: Request for IESO Comment Letter

BY COURIER

March 3, 2017

Ms. Miriam Heinz
Regulatory Coordinator
Independent Electricity System Operator
120 Adelaide Street West, Suite 1600
Toronto, ON, M5H 1T1

Dear Ms. Heinz:

Re: Hydro One Remote Communities Inc. – Letter of Comment

Hydro One Remote Communities Inc. ("Remotes") is preparing to file a Cost of Service ("CoS") rate application for 2018. As part of this application, Remotes will be including a Distribution System Plan ("DSP") which must be accompanied by a letter of comment from the Independent Electricity System Operator ("IESO").

Remotes' application is subject to the Ontario Energy Board's ("OEB") Filing Requirements for Electricity Transmission and Distribution Rate Applications. These requirements (Chapter 5) indicate the OEB expects the IESO comment letter will include:

- the applications it has received from renewable generators through the [Feed-in Tariff] ("FIT") program for connection in the distributor's service area;
- whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan.

In regards to the above points and the letter of comment, please note that:

- Remotes' service area is not eligible for the FIT program and, therefore, there are no FIT applications for connection in Remotes' service area;
- Remotes routinely consults with the IESO on various matters as appropriate;
- Each of the communities served by Remotes is electrically isolated and not connected to the bulk transmission system. Therefore co-ordination with other distributors and/or transmitters on implementing REG investments is not necessary.
- The Remote Community Connection Plan is still under development for Remotes' region.

Remotes respectfully requests a letter of comment from the IESO addressing these points, as appropriate, by April 3rd, 2017. If you have any questions, or require additional information, please contact our Regulatory Affairs group at Regulatory@HydroOne.com.

Sincerely,

ORIGINAL SIGNED BY KAREN TAYLOR

Karen Taylor
Senior Director, Applications Delivery
Regulatory Affairs

Appendix G: IESO Comment Letter

IESO Letter of Comment

Hydro One Remote Communities Inc.

Renewable Energy Generation Investments

April 4, 2017

Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Hydro One Remote Communities Inc. – Renewable Energy Generation Investments

On March 3, 2017, the IESO received a letter from Hydro One Remote Communities Inc. ("Remotes") in order to obtain a letter of comment from the IESO pertaining to Renewable Energy Generation Investments Information as part of its 5-year Distribution System Plan. The IESO has the following comments:

The letter contained no REG investments that required the IESO's comment. The IESO acknowledges that communities served by Remotes were/are not eligible for the FIT program, and therefore there is no need for REG Investments or co-ordination with other distributors and/or transmitters on this subject.

With respect to planning, the IESO confirms that Remotes is an active participant to the Remote Community Connection Plan for which the government issued an Order in Council on July 29, 2016, confirming the need for the project to connect 21 remote communities. Remote community connections are underway and supported by the government designating Wataynikaneyap Power as the transmitter for connecting 16 communities and the new line to Pickle Lake. Remotes is working closely with the IESO with respect to the ongoing work required to connect the remaining five remote communities.

The IESO looks forward to working further with Hydro One Remote Communities Inc. on planning for the connection of remote communities, and appreciates the opportunity to provide its letter of comment as required.

[1] 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.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Appendix H: Hydro One Remotes Roof Assessment Report

February 13, 2014

John Supinski
Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9
(807)474-2808

RE: 2013155 – DIESEL GENERATOR STATION ROOF ASSESSMENT REPORT & RECOMMENDATIONS (VARIOUS)

Dear John,

The office of FORM Architecture Engineering was requested by the owner(Hydro One) to review existing roof construction for four(4) of their diesel generator stations within various remote communities of northern Ontario and to provide feedback to Hydro One on the condition of said roof construction, along with recommendations for future use. This review was requested to determine what, if any, capacity remained within the existing roof structure to accommodate an increase in thermal performance in order to alleviate persistent ice formation along the roof edges. The four(4) diesel generator stations selected by Hydro One for review were in the following communities; Kingfisher Lake, Lansdowne House, Big Trout Lake, and Weagamow First Nation communities.

Contained within the body of this report is a general description of the construction and current condition of each of the four(4) diesel generating station roof structures. The office of FORM Architecture Engineering is to provide recommendations on enhancing the longevity of existing roof construction for the above mentioned locations, as well as potential improvements to thermal performance of the roof structures.

KINGFISHER LAKE: EXISTING CONDITIONS

The diesel generator station located in Kingfisher Lake is a manufactured steel building(see photo#1). The exterior dimensions of the building in question are 19.51m(64'-0")x7.32m(24'-0").The roof structure consists of steel liner panels acting as the interior ceiling and doubling as the air/vapour barrier. The roof's thermal layer is comprised of ±280mm(±11") of fiberglass batt insulation(see photo#2) which equates to an approximate R-value of 40 for dry, uncompressed fiberglass insulation. Roof/ceiling support consists of horizontal steel L51x51x6.4(L2x2x¼") angles at 2440mm(8'-0") on-centre. Steel Z-girts run perpendicular to the horizontal structure to support the liner panel ceiling below. To create the sloped roof structure above the ceiling, steel roof panels are supported at the eaves, peak, as well as at the mid-span. Support at the eave is provided by the exterior wall framing, while the mid-span roof panel support is provided at both edges of every panel with what appears to be a vertical 51x51x0.91mm (2x2x20ga.) member(see photo#3) down to the ceiling framing & heavy gauge clips at the roof panels above. Roof panel support at the peak is provided by a pair of heavy gauge 'Z' girts, connected side-by-side at their legs and supported at 2440mm(8'-0") on-centre with vertical L51x51x6.4 (L2x2x¼") members directly to the horizontal members below(see photos#4-5). It was not feasible to get a direct measurement of the roof slope while onsite due to limited access, but existing slope of this roof appears to be ± 4:12.

The current condition of the existing roof structure appears to be decent. There are no observable signs of condensation issues either within the building or within the attic space. Ventilation is provided at both gable ends by means of a louver grill which is adequate for the main attic section, but a lack of ventilated airspace at the eaves is the likely cause of heat transfer and subsequent ice formation at the roof edge above(see photo#3). Though not apparent during the time of inspection, the owner's representative had expressed concerns over the above mentioned ice formation at the eaves of this building and the ensuing maintenance and safety issues that accompany this ice formation. The owner had previously taken steps to prevent ice formation from sliding from the roof onto the ground by attachment of bent light gauge steel to act as an ice-stop. Measures to-date are only temporary as the ice-stops are connected to light gauge roof panels only and fasteners continually pull out of the light gauge material. The current preventative methodology entails a great deal of maintenance to ensure performance. In addition, continual re-attachment of the temporary ice-stop material provides new penetrations through the roof panels, and compromises the effectiveness of the steel roofing panels to resist the elements(see photo#1).

LANSDOWNE HOUSE: EXISTING CONDITIONS

The diesel generator station in Lansdowne House consists of multiple manufactured steel buildings pieced together with various roof elevations and slopes. The portion of the building in question is 15.88m(52'-1")x7.32m(24'-0") with an eave height of 3.60m(11'-10") and a peak height of 4.24m(13'-11"). The slope of the existing roof is 2:12(see photos#6-7 – portions of building with lower roof elevations) though there are subtle differences in roof slope between the two lower elevation portions of roof, as well as the higher elevation roof structure. Roof construction for the 3.66m(12'-0") length addition completed in 1994(identified as Control Room 'A') are similar to that of the Kingfisher Lake Diesel Generator Station in that steel liner panels make up the ceiling and act as the air/vapour barrier, along with a similar construction type for the roof panel supports(see photos#8-10). There are no mid-span supports provided for the roof panels in this addition. It was observed that there is approximately 280mm(11") of fiberglass batt insulation, equating to an approximate R-value of 40 for a dry, uncompressed insulation layer. Roof structure for the 12.19m(40'-0") length section of building immediately adjacent the 1994 addition noted above, also at the lower roof elevation, is constructed from steel stud trusses which appear to be 1.22m(4'-0") on-center with steel 'Z'-girts above to support steel roof panels. The remainder of the existing structure which houses additional diesel generators is in a newer manufactured steel building. This building has a higher eave elevation of 4.37m(14'-4") and is not an area of concern for the owner(refer to photos#6-7).

Within the attic space of the additions, the steel roof panels and structure appear to be sound. There was no observed indications of condensation occurring within the space. There was some minor deterioration visible on the roof panel edges at the exterior of the building along the eaves, though not easily identifiable from any photographs. A major factor influencing this wear is most likely the consistent ice formation and subsequent freeze-thaw cycles that the eave roof panels are subjected to throughout the seasons. At the time of inspection, ice formation had already begun at both eaves of the lower portion of the building. The majority of the ice formation had thus far occurred at the eave side adjacent to the diesel storage tanks(side of building shown in photographs) and within proximity to the diesel generator room. The higher degree of ice formation at this location could be contributed to the diesel generator being the main heat source for this portion of the building. As with the roof at Kingfisher Lake, there is no ventilation allowed at the eave locations within the attic space(refer to photo#9), and as the insulation becomes compressed at the exterior wall, the potential for heat transfer becomes much greater and is the likely cause of ice formation at these locations.

At the time of inspection, there was no visible ice formation on the portion of the building with the higher roof elevation, with ice formation occurring at wall penetrations for exhaust vent locations only.

BIG TROUT LAKE: EXISTING CONDITIONS

The diesel generator station in Big Trout Lake appears to be from more than one manufactured steel building. All construction appears similar, as all exterior dimensions are consistent in terms of building width, eave elevation and roof slope. Roof construction spans the entire width of the building and bears upon structure at the exterior walls. Structure for the roof at the Big Trout Lake Generator Station is from fabricated structural steel trusses at 2.44m(8'-0") on-center. Top and bottom chords are comprised of 64mm(2½") square steel HSS sections and 25mm(1") square HSS sections for all vertical web members. Diagonal web members are from 38x10mm(1½"x3/8") steel flat bars(see photos#11-12). As with both the Kingfisher Lake and Lansdowne House Generator Stations, steel liner panels form the ceiling, as well as act as the air/vapour barrier and support the attic insulation. Thermal performance of the roof structure is provided by 280mm(11") of fiberglass batt insulation, which would equate to an approximate R-value of 40 for a dry, uncompressed insulation layer. Steel roof panels are supported at the eave, mid-span and peak by 125mm(5”) steel ‘Z’-girts. Roof slope appears to be at 2:12, though it could not be verified at the time of inspection.

Appearance of both the ceiling and roof panels were fair. There were no visible signs of condensation occurring within the attic space or any other indications that the performance of the steel panels has substantially deteriorated. Ice formation was not observed along the roof eaves during assessment, though the owner’s representative indicated that this station is prone to ice formation along its eaves throughout the winter season. Ventilation for this roof construction is limited to louvers at each gable end, and a lack of airspace at the eaves due to minimal truss heel height and insulation thickness is again a likely cause of heat transfer and subsequent ice formation at the eave locations(refer to photo#13).

WEAGAMOW: EXISTING CONDITIONS

Weagamow’s diesel generator station is, once again, a steel manufactured building. The station itself appears to be one building as additional structures tied into the base construction match in dimensions. The building itself is 19.58m(64’-3”) long and 7.32m(24’-0”) wide. Roof construction consists of horizontal steel liner panel acting as the ceiling and as the air/vapour barrier for the roof. Roof framing is from steel stud trusses @ 2.44m(8’-0”) on-center. Truss top and bottom chords are from 152mm(6”) steel stud, with 102mm(4”) steel stud web members. An exact thickness for truss members could not be obtained, though visual inspection indicated a material thickness of 0.91mm(20ga.) steel based upon standardized colour markings visible on steel members(white paint indicates 20ga material – see photo#14). Above steel stud trusses sits 102x3.2mm(4”x1/8”) cold-formed channel purlins at the eaves, mid-span, and peak for which steel roof panels sit atop(see photos#14-15). Visual observation of the attic space revealed that there appeared to be only a single 140mm(5½”) batt of fiberglass insulation throughout the structure, which would approximately be equal to an R-value of 15 for a dry, uncompressed insulation layer.

Ventilation for the entire attic space is from louver grills at each gable end of the structure and is most likely insufficient for the volume of attic space. In addition, there is no air space at the exterior wall locations due to insufficient heel height on the roof trusses(refer to photo#16). At the time of inspection, exterior temperatures were -27°C, though it was noticeably warmer inside the attic space which would indicate significant heat loss from the interior space as was also noticed by the significantly lower amount of snow build-up on the main roof as compared to the fuel line tray immediately adjacent(see photo#17). Though it is not readily apparent from photographs taken while FORM was onsite, photographs supplied by the owner’s representatives indicate that roof panels are beginning to show signs of deterioration on the exterior(see photo#18 – some signs of finish deterioration seen).

RECOMMENDATIONS:

A number of factors need to be considered in determining an effective recommendation for the above four(4) diesel generator stations roof maintenance procedures.

The request of the owner is to provide a solution that will minimize, if not eliminate ice formation along the roof eaves as this causes both maintenance as well as health and safety issues throughout the winter months of operation. The owner also requested a minimum R-value for all four(4) roof structures to be, at minimum, a value of 30. In addition, there is a requirement to utilize only non-combustible materials for additional structure and cladding for modifications to any of the facilities (ie. steel stud framing, metal roof panels, aluminum flashing, etc.). As all four(4) locations are situated in remote locations of northern Ontario, with limited transportation access(ie. winter roads for shipping material to site), solution options should make considerations for design optimization and material quantities wherever possible.

From site observations of all four(4) facilities, as well as subsequent review of existing construction, it is the opinion of FORM Architecture Engineering that ice formation on all four diesel generator stations is largely the result of a lack of tempered air space directly above the existing roof insulation layer at eave locations. This lack of tempered air space at eave locations facilitates thermal bridging and subsequent heat loss directly to the metal roof panels above. Any snow present at these locations proceeds to melt and migrate down to the roof edge. Once melted snow reaches a point of the façade where exterior surfaces are below the freezing point, and in combination with outside air temperatures being below freezing, water will re-solidify as ice. This process will continue throughout the winter months provided that snow accumulates upon the roof of the structure and there is heat generation from within. Additionally, in the case of the Weagamow diesel generator station, insufficient insulation provided throughout the roof assembly further contributes to the heat loss and eventual ice formation(as described above) at the eave locations.

In order to expedite the process of remediation, minimize cost impacts to the owner, and based upon assessment of the existing roof structure, the following are recommendations to minimize further ice formation and any damage resulting at the above mentioned generator facilities.

KINGFISHER LAKE, LANSDOWNE HOUSE & BIG TROUT LAKE GENERATOR STATIONS:

The three(3) above mentioned facilities have sufficient insulation performance as required by the owner. As such, it is not recommended to proceed with providing additional insulation over and above what is existing in these facilities. Given the lack of ventilation at the eave locations, additional insulation added to the attic space would fail to address the persistence of ice formation along the building eaves.

Through observations on site, and subsequent discussions with a local steel building supplier, it has been determined that the existing roof panels and framing are sufficient to support the minimal additional dead load applied by the application of new roof panels and support framing directly to the existing panels. Discussion with the steel building supplier has indicated that existing steel roof panels are 406mm(16") wide by 0.61mm (24ga.) thick with 76mm(3") ridges at their interlock joint. This panel type is consistent for all of the roof additions which are supported at the eaves, peak and mid spans. The steel roof panels for one addition at Lansdowne House in which there are no mid span supports is believed to be from 406mm(16") wide by 1.9mm(14ga.)thick sheet steel with 102mm(4") ridges at their interlock.

After assessment of the existing steel roof panels, and steel framing below, it is recommended that for the above three(3) locations, the formation of tempered air space above the existing panels be created. In addition, proper airflow from soffit to the ridge should also be created within the new tempered air space. By providing a tempered space above the existing steel roof, any heat loss which would occur at the eave location must now be transferred through the air space before transmitting heat to the new roof panels above. Creating proper airflow into the air space by allowing fresh cold air in from the soffit and venting out at the ridge, heat transfer through the air space to the new steel roof panels can be significantly reduced.

It is proposed that the owner create an area of tempered air space above existing roof panels by the addition of 152mm(6") perforated heavy gauge steel 'Z' girts running parallel to the ridge at 610mm(2'-0"c/c) and fastened at each existing roof panel ridges with self-tapping sheet metal screws. Soffit venting can be achieved by way of sheet metal framing and perforated sheet at the eave locations, and ridge venting to be provided by a manufactured ridge vent suitable for metal roofing applications. In addition, consideration should be made to incorporate snow-stops along the access side at the Kingfisher Lake generator facility. This station has a steeper pitched roof slope, which increases the potential for snow to fall from the building roof. To accommodate snow-stops, proper sub-framing is to be installed prior to placement of any new roofing panels. Refer to the attached drawing sheet S2 – Big Trout Lake Plans/Elevations/Details(24x36). Details for Kingfisher Lake and Lansdowne House facilities are similar, drawing sheets for these facilities yet to be completed(scheduled for remediation by the owner in 2015).

WEAGAMOW GENERATOR STATION:

In addition to the ventilation issue identified for the other three diesel generator stations, Weagamow Generator Station was also observed to have insufficient insulation within the attic space to what is required by the owner. As there is limited space within the existing attic for placement of additional batt insulation, the recommendation of FORM for this structure is as follows: (1) Removal of existing roof panels to facilitate the addition of another 140mm(5½") fibreglass batt insulation, and (2), similar to the recommendations for the three other stations above, creation of a tempered air space above existing by way of 305mm(12") perforated heavy gauge steel ‘Z’ girts running parallel to the ridge at 610mm(2’-0”)c/c and fastened to each steel stud roof truss with self-tapping sheet metal screws. Soffit and ridge venting are to be similar to as noted above. Refer to the attached drawing sheet S1 – Weagamow Plans/Elevations/Details(24x36).

LIMITATIONS:

Findings and recommendations by FORM Architecture Engineering have been based upon visual assessment and, in part, on information provided by others. Unless noted otherwise, FORM has assumed this information to be correct for the development of the recommendations contained within this report. There is a possibility that unforeseen conditions may be encountered on site during implementation of any or all of the recommendations listed within this document that have not been documented. Should any such unforeseen instance(s) occur, the owner should notify the consultant to determine what, if any impact the discoveries have on the above noted recommendations given.

Please do not hesitate to contact the offices of FORM Architecture Engineering if there are any questions, concerns, or comments about information provided within this report.

Sincerely,

Jamie A Pilot, P.Eng.
Associate Partner

Attachments:

- Site Photographs 1-18(10 Pages)
- S1 – Weagamow Plans/Elevations/Details (24x36)
- S2 – Big Trout Lake Plans/Elevations/Details (24x36)

Attachments Not Included:

- S3 – Kingfisher Lake Plans/Elevations/Details (24x36)
- S4 – Lansdowne House Plans/Elevations/Details (24x36)

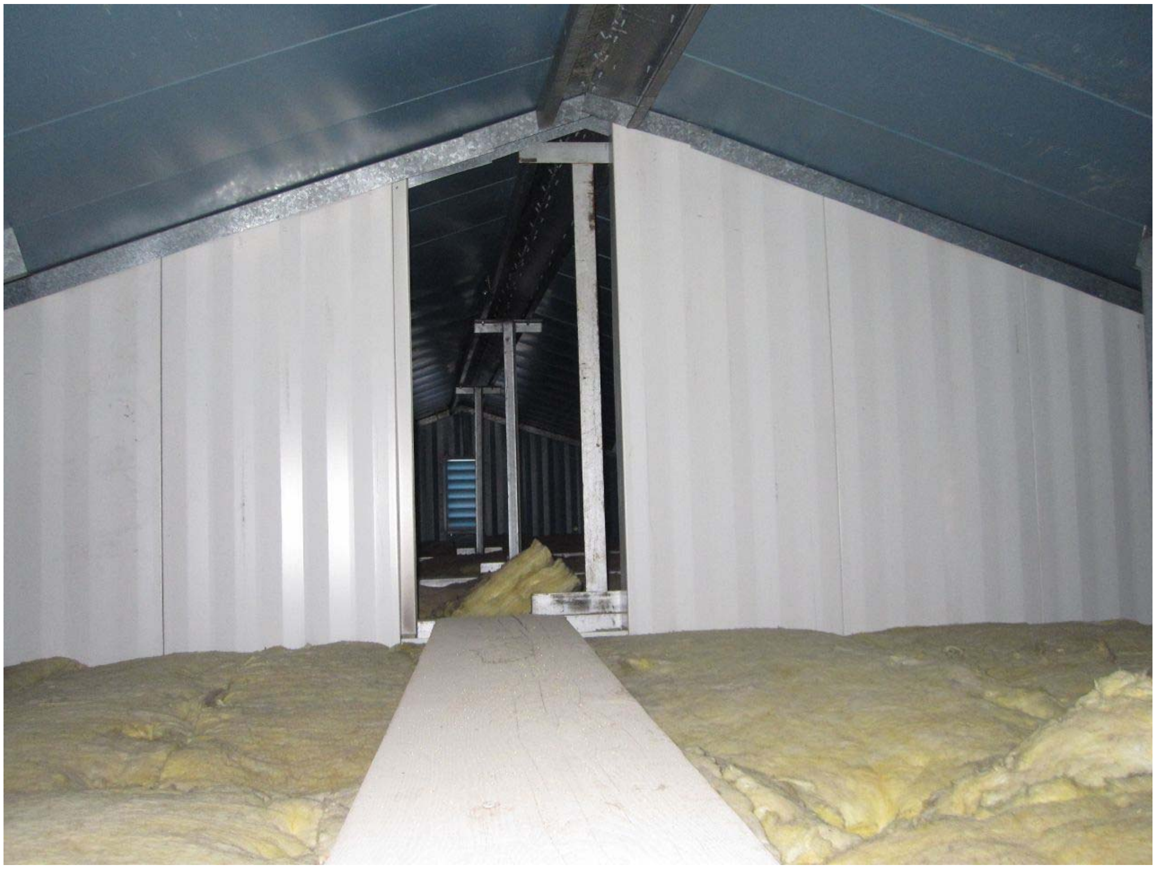
SITE PHOTOGRAPHS

Photo#1 – Kingfisher Lake Diesel Generator Station (Exterior)

Photo#2 – Existing Roof Insulation Thickness (Kingfisher Lake)

Photo#3 – Roof Panel Mid-Span & Eave Support (Kingfisher Lake)

Photo#4 – Roof Panel Peak Support (Kingfisher Lake)


Photo#5 – Roof Panel Peak Support (Kingfisher Lake)


Photo#6 – Lansdowne House Diesel Generator Station(Exterior)


Photo#7 – Existing Roof Elevation Transition (Lansdowne House)


Photo#8 – Roof Panel Peak Support Framing (Lansdowne House)

Photo#9 – Roof Panel Eave Support/Insulation (Lansdowne House)

Photo#10 – Roof Construction Transition (Lansdowne House)

Photo#11 – Roof Framing (Big Trout Lake)

Photo#12 – Roof Truss Top Chord (Big Trout Lake)

Photo#13 – Roof Panel Support/Insulation (Big Trout Lake)

Photo#14 – Roof Framing (Weagamow)

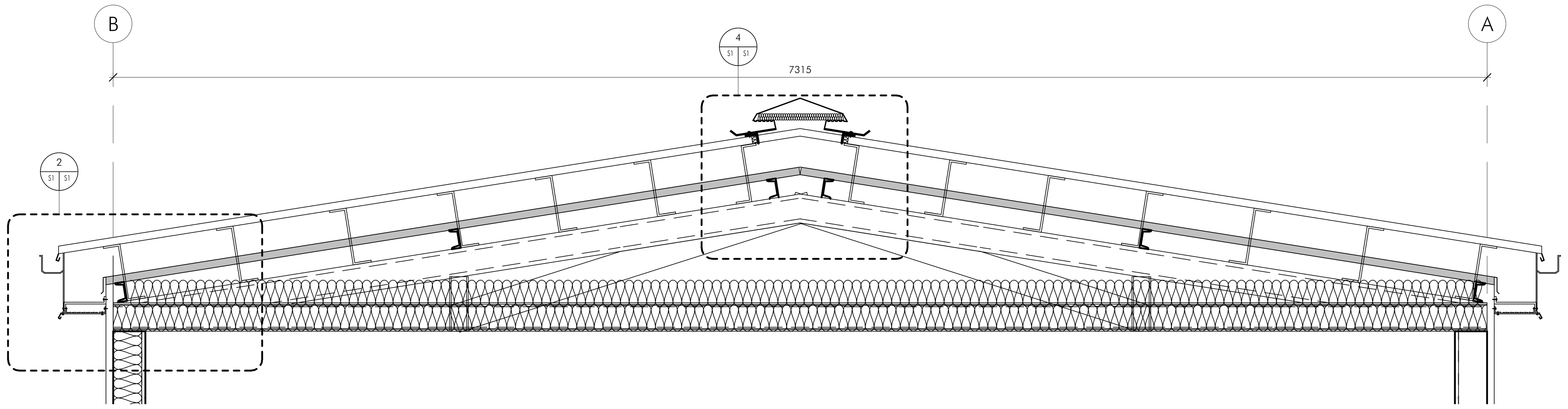
Photo#15 – CFC Purlins (Weagamow)

Photo#16 – Insufficient Air Space (Weagamow)

Photo#16 – Beginnings of Visible Ice Formation (Weagamow)

Photo#17 – Exposed Fuel Line Tray & Visible Heat Loss (Weagamow)


Photo#18 – Visible Heat Loss & Roof Panel Deterioration Signs (Weagamow)



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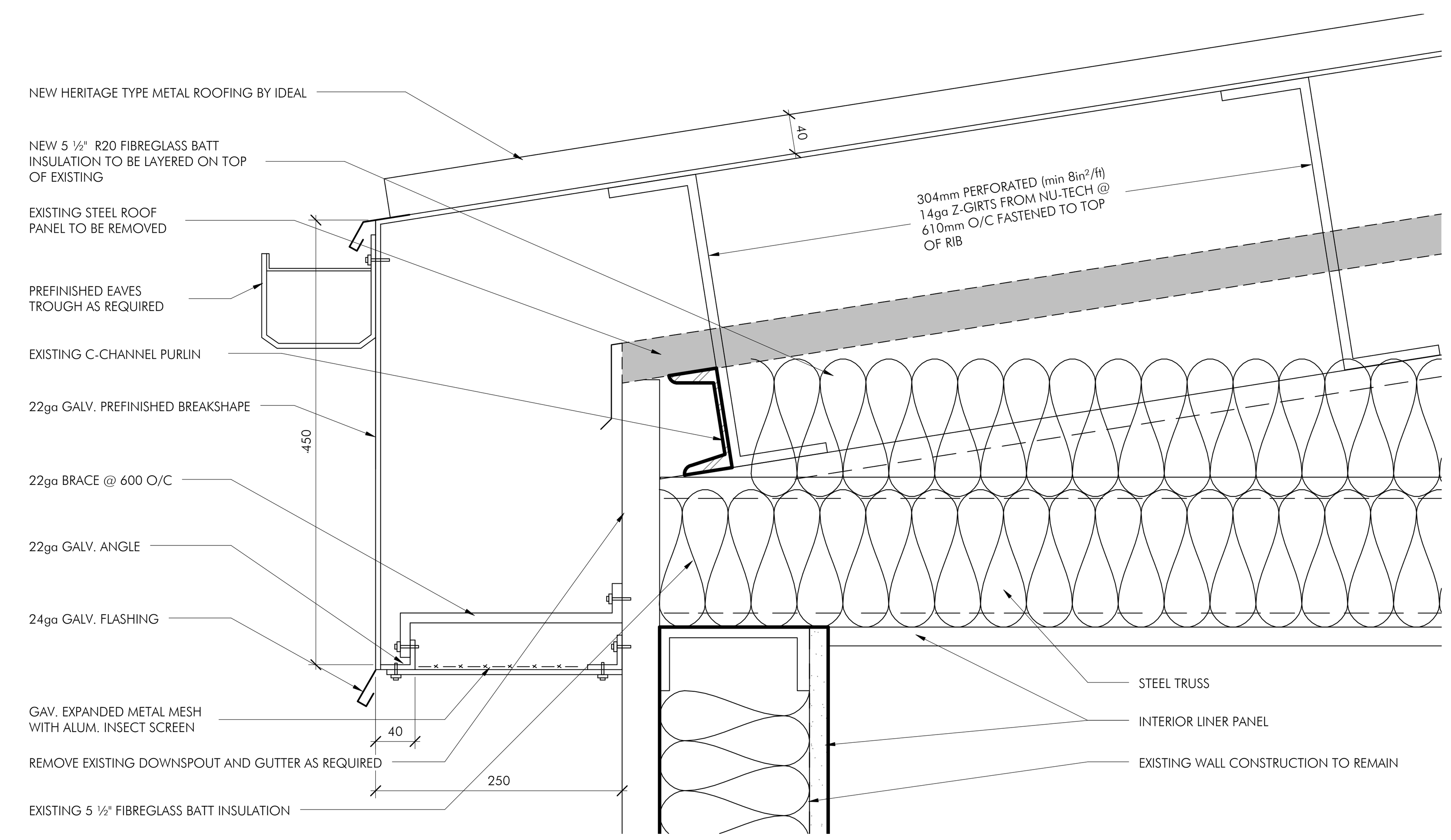

2 CALLOUT AT EAVES
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REVISION	DATE	DESCRIPTION

SEALS:

LICENSED PROFESSIONAL ENGINEER
2014/07/17
J. A. PILOT
100101682
PROVINCE OF ONTARIO

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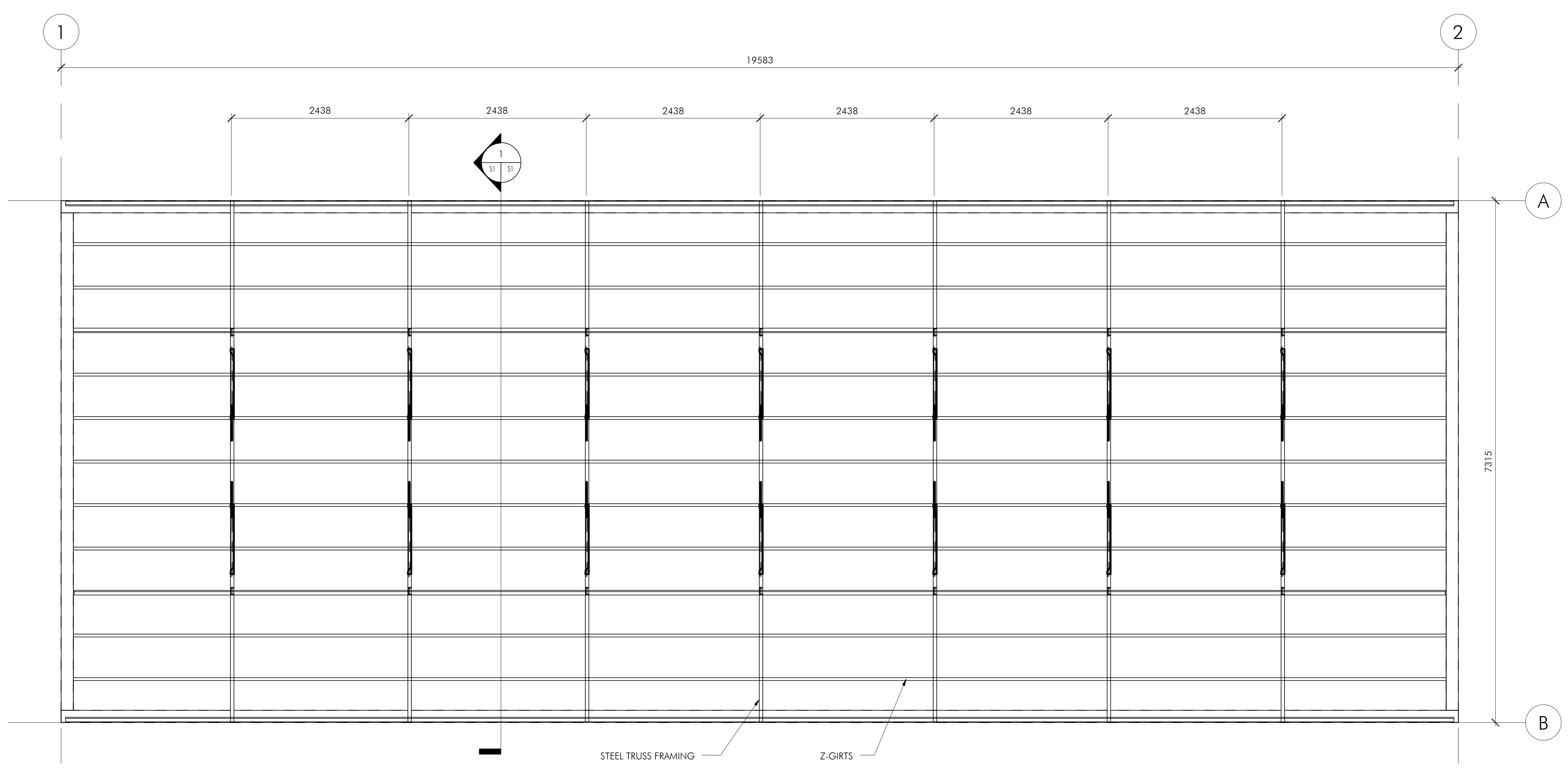
FORM ARCHITECTURE ENGINEERING
131 Court Street North, Thunder Bay, ON P7A 4V1 Canada
p 807.345.5582 f 807.345.4093 e info@formarchitecture.ca

BETTER PLACES FOR PEOPLE
www.formarchitecture.ca



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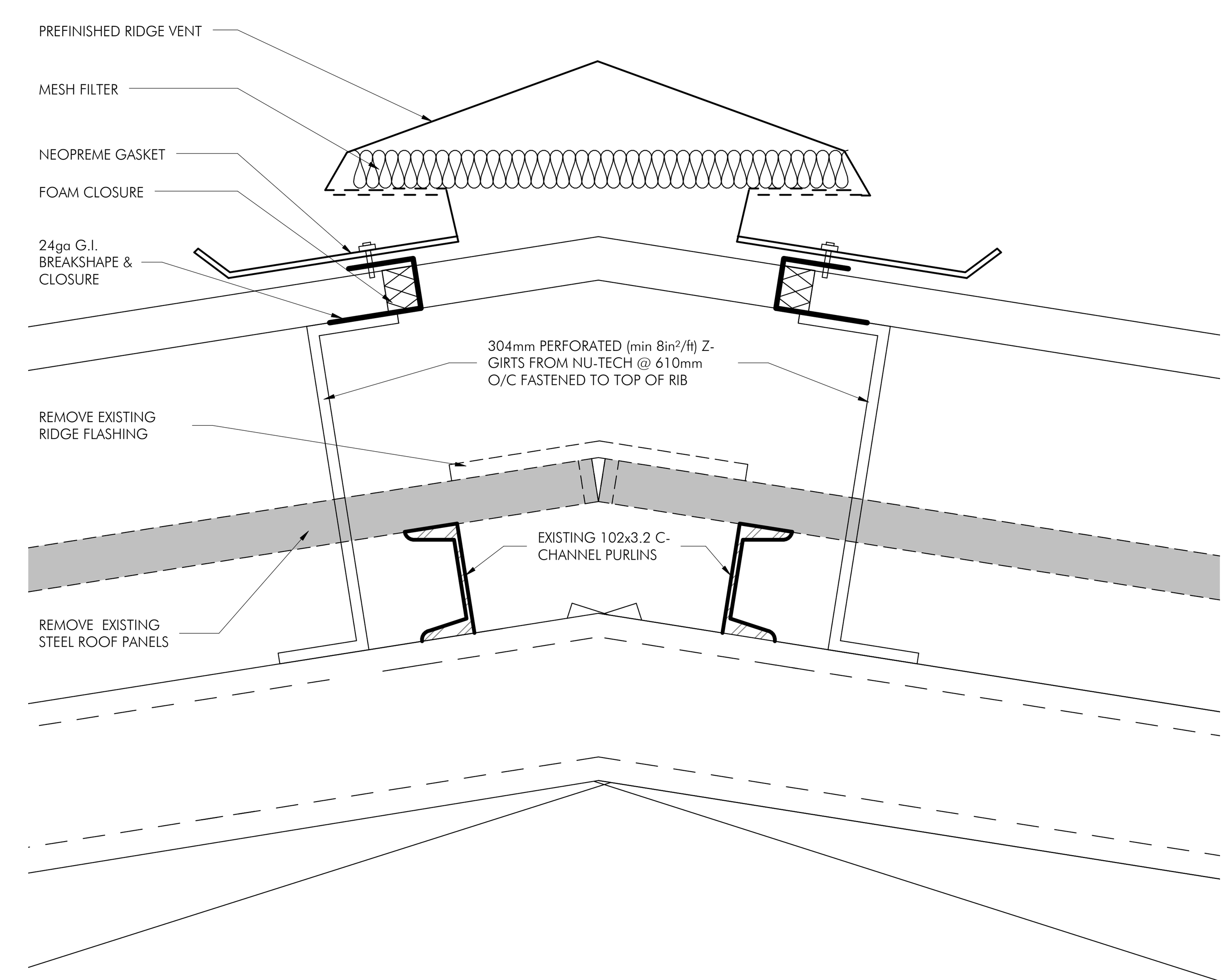

4 CALLOUT AT PEAK
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PROJECT NAME:

Hydro One

Remote Roof Upgrades

SHEET TITLE:

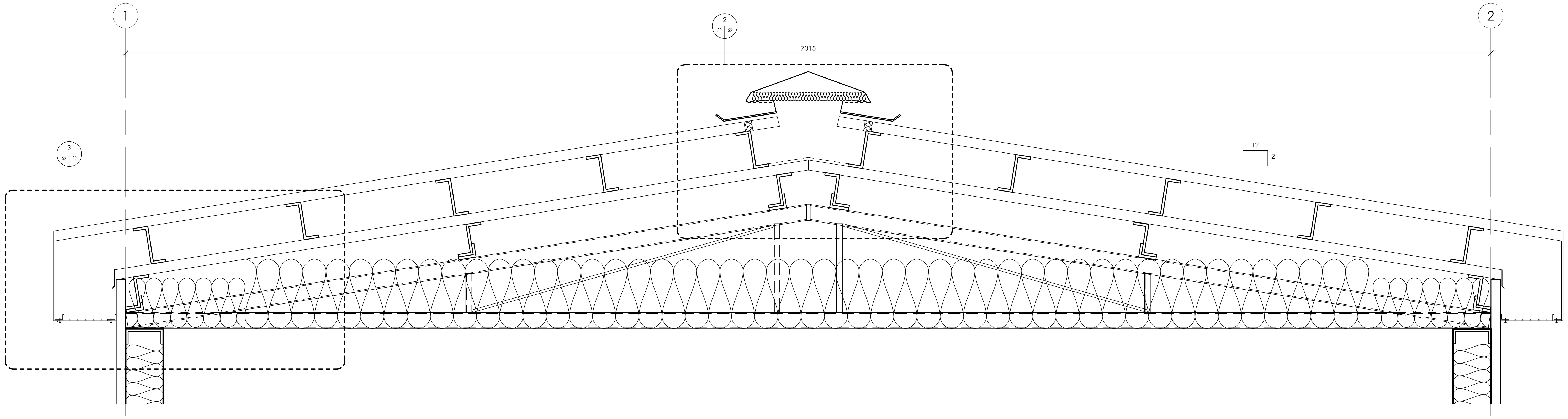
WEAGAMOW PLAN & DETAILS

DATE: 14/02/13

DRAWN: KPD

PROJECT: 2013155

S1



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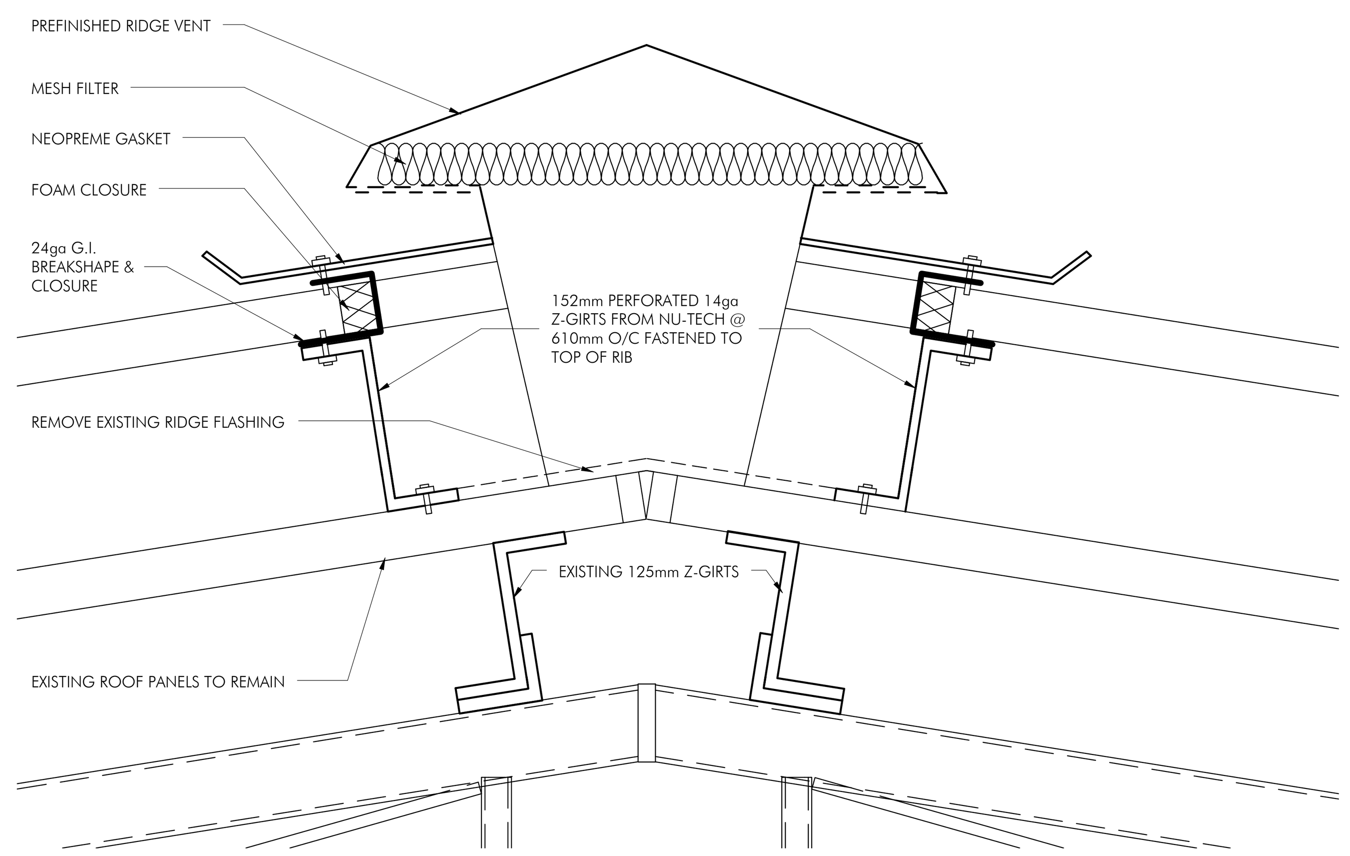

2 S2 | S2 CALLOUT @ PEAK
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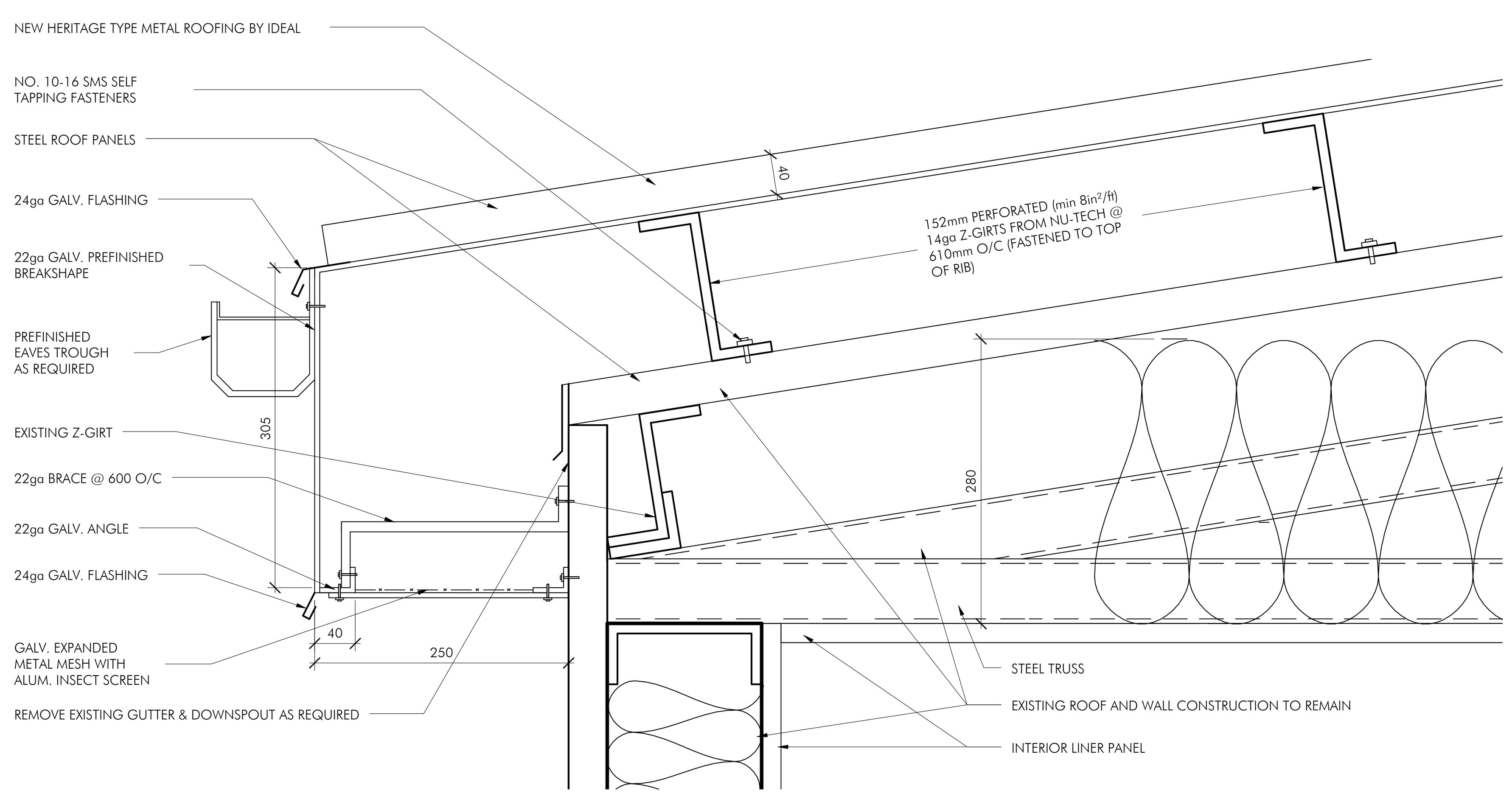

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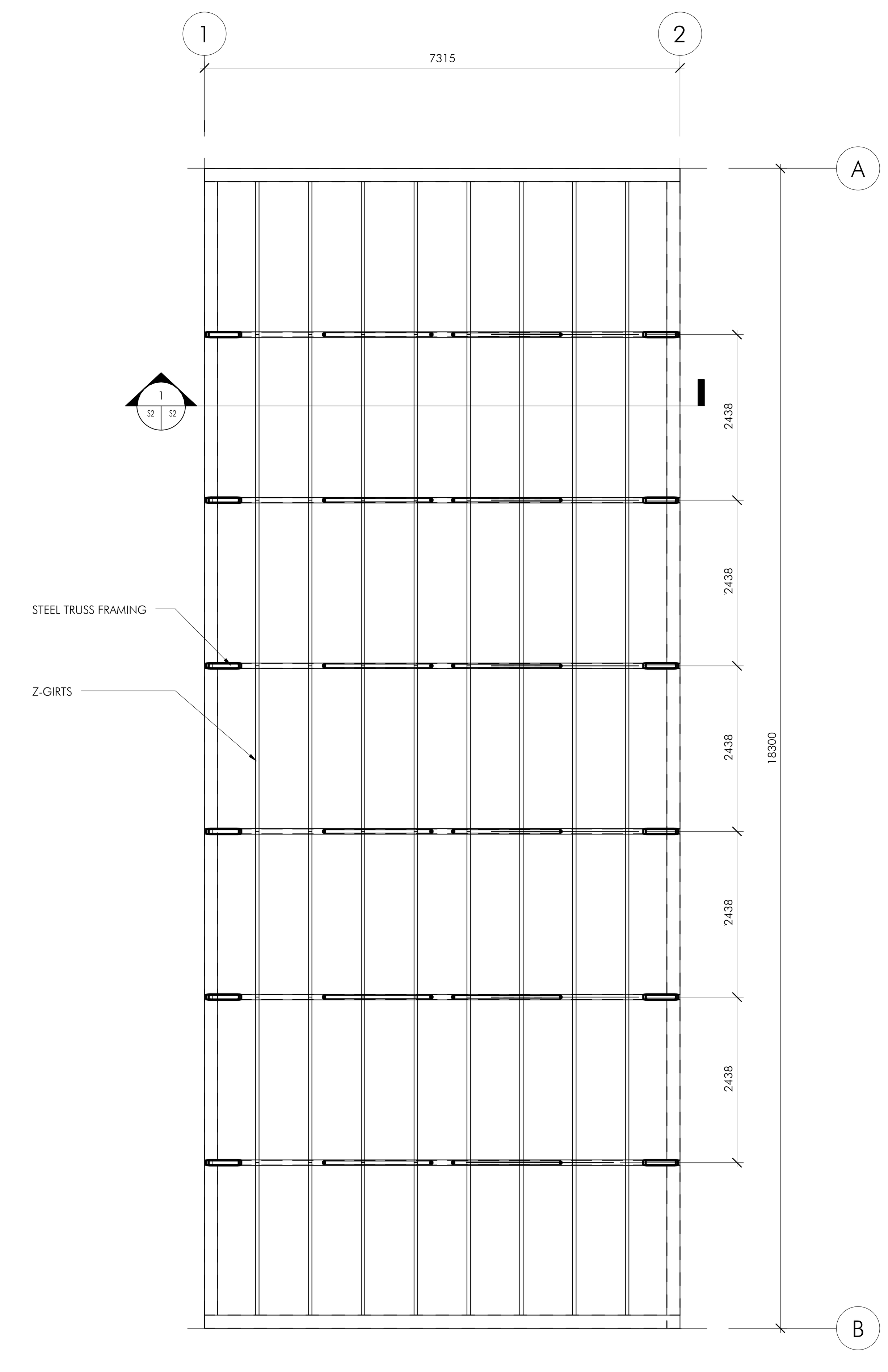

4 S2 ROOF PLAN
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"0"	14/02/13	ISSUED FOR CONSTRUCTION
REVISION	DATE	DESCRIPTION

SEALS:

LICENSED PROFESSIONAL ENGINEER
2014/02/13
J. A. PILOT
100101682
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FORM ARCHITECTURE ENGINEERING
131 Court Street North, Thunder Bay, ON P7A 4V1 Canada
p 807.345.5582 f 807.345.4093 e info@formarchitecture.ca

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www.formarchitecture.ca

PROJECT NAME:

Hydro One

Remotes Roof Upgrades

SHEET TITLE:

BIG TROUT LAKE PLAN & DETAILS

DATE: 14/02/13

DRAWN: KPD

PROJECT: 2013155

S2

MAKING IT POSSIBLE

19 July 2017

Una O'Reilly
Business Integration Manager
Hydro One Remote Communities Inc.
12th Floor, North Tower
483 Bay Street,
Toronto, ON; M5G 2P5

Dear Una,

Re: Consolidated Distribution System Plan

This letter is to confirm that METSCO Energy Solutions Inc. has assisted Hydro One Remote Communities Inc. (Remotes) with the creation of a Consolidated Distribution System Plan (DSP) as part of Remotes' 2018 Cost of Service Application. The DSP has been prepared in accordance with the Ontario Energy Board's (OEB's) *Chapter 5 Consolidated Distribution System Plan Filing Requirements dated 28 March 2013.* Remotes' DSP supports the four key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (*RRFE*): customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Best regards,

Alex Bakulev
Vice President, Strategy and Assets

METSCO Energy Solutions
metsco.ca

Suite 215; 2550 Matheson Blvd. East,
Mississauga, ON, L4W 4Z1
Phone: 905–232–7300
Fax: 905–232–7405
Email: info@metsco.ca