NORTH OF DRYDEN
INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | January 27, 2015

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.

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Summary of Plan Highlights

- Drivers for increased electricity demand in the areas surrounding Red Lake, Pickle Lake and Ring of Fire include *connecting remote First Nation communities and growth in the mining sector*.

- The OPA recommends a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake and upgrades to existing lines between Dryden and Red Lake for immediate implementation to address near- and medium- term needs for the Pickle Lake and Red Lake areas.

- Incremental longer term solutions to supply Ring of Fire and Red Lake are not required at this time. Longer term options will be re-evaluated in the next planning cycle (1-5 years).

- Options to supply the Ring of Fire include transmission utilizing an East-West or North South corridor, or on-site generation. East-West and North-South transmission options are comparable in cost under the high demand scenario and the potential need for a transmission line should be considered in the planning of a common infrastructure corridor to the Ring of Fire.

- Long-term options for the Red Lake area include local gas generation or new transmission.

Summary of Updates from August 2013 draft IRRP

- Revised demand forecast used different methodology, includes updated data and is represented by three scenarios – reference, high and low; August 2013 draft included high and low scenarios, but did not include a reference scenario.
- Revised demand forecast indicates relatively higher forecasted demand in the Pickle Lake subsystem, and relatively lower forecasted demand in the Red Lake subsystem than in the August 2013 draft.
- Recommendation is for new 230 kV line to Pickle Lake in this version; voltage recommendation was not specified in the August 2013 draft.
- Recommended line upgrades from Dryden to Red Lake are expected to be sufficient to the end of the planning period for the reference and low forecast scenarios, and to 2030 for the high forecast scenario. The August 2013 draft indicated that the upgrades may be insufficient in the medium-term for the high scenario.
- Recommendation to discuss reactive services of Manitou Falls GS with OPG, as per OPG’s written submission.
- Revised economic analysis methodology – refer to Appendices 10.6, 10.7, and 10.8 for details.

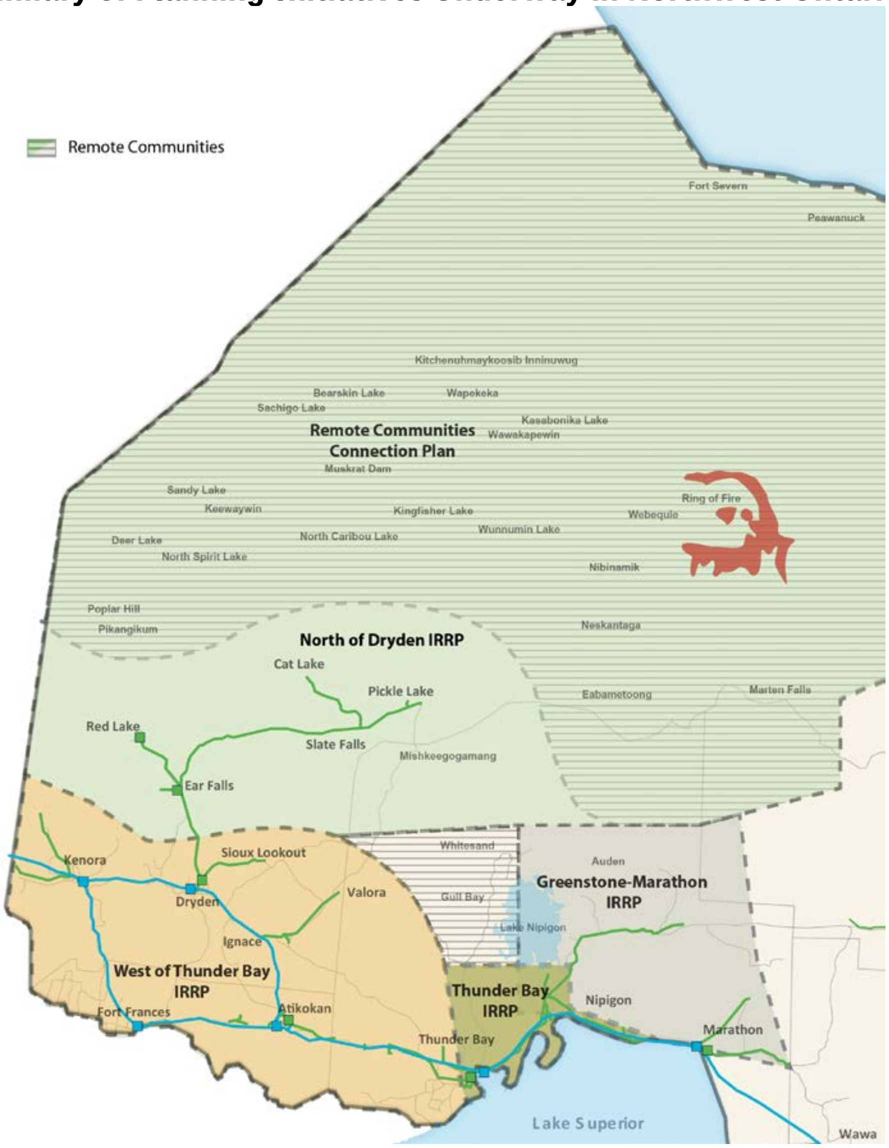
1 EXECUTIVE SUMMARY

Context and Purpose

The purpose of the North of Dryden Integrated Regional Resource Plan (“regional plan”, “North of Dryden IRRP”, or “IRRP”) is to identify the near-term and medium- to long-term electricity supply needs of the area and assess options that are available to address the needs in a timely, reliable and cost-effective manner. The IRRP is intended to provide the overall planning context to address regional supply adequacy and reliability needs.

The North of Dryden IRRP is one of several electricity planning initiatives that the the Ontario Power Authority (“OPA”) is undertaking for the Northwest Ontario region. Figure 1 identifies the IRRP initiatives currently being undertaken by OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region. This includes requirements at Pickle Lake and Red Lake related to the connection of the 21 remote First Nation communities (“remote communities”) that are economic to connect, as outlined in the Remote Community Connection Plan as well as new mining developments forecasted in the area. It also coordinates with the West of Thunder Bay IRRP, ensuring that the West of Thunder Bay transmission system is able to accommodate the expected growth north of Dryden. The North of Dryden IRRP will also coordinate options related to supply to the Ring of Fire with the Greenstone-Marathon IRRP.

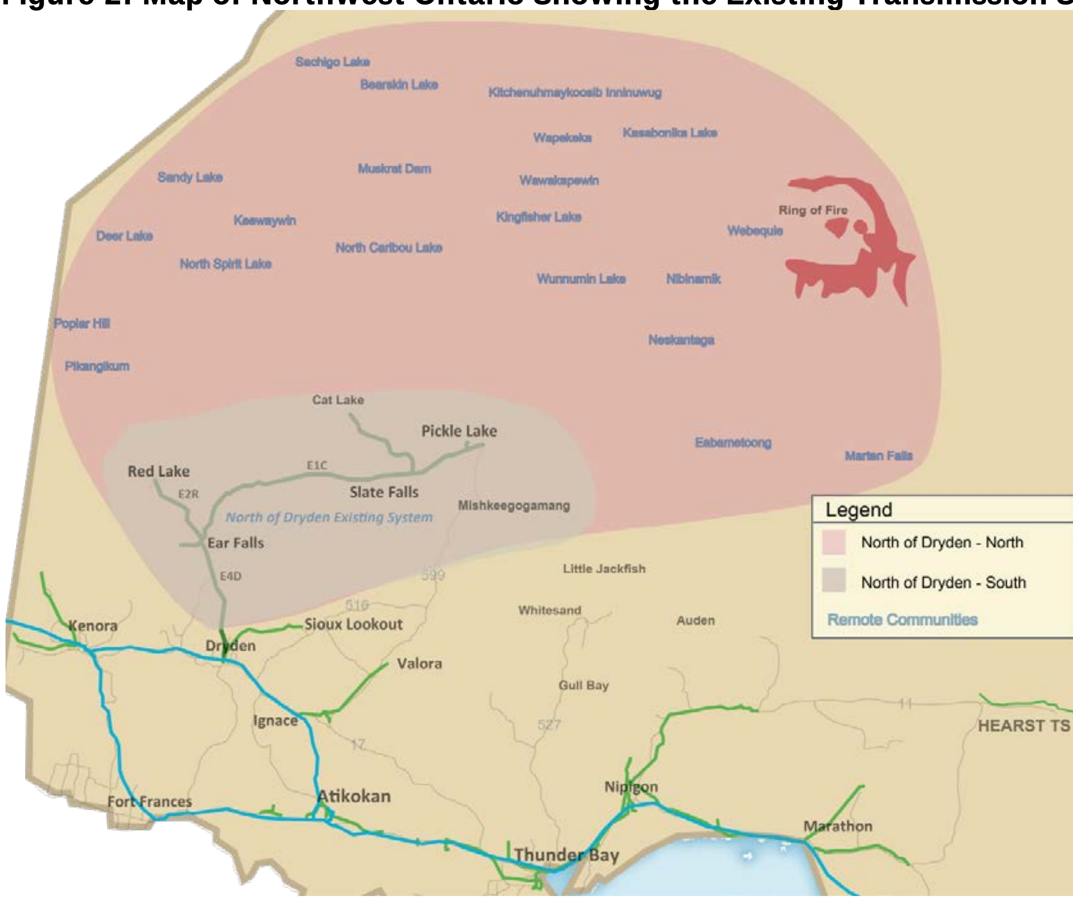
Figure 1: Summary of Planning Initiatives Underway in Northwest Ontario



The North of Dryden sub-region is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario (“MNO”). The southern portion of the sub-region (shown in Figure 2) is currently served by Ontario’s transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest and Pickle Lake to the northeast. Existing mining activity is primarily located in this southern portion of the North of Dryden sub-region and is largely focused around the towns of Ear Falls, Red Lake and Pickle Lake. The northern portion of the North of Dryden sub-region (shown in Figure 2) contains the

21 remote First Nation communities which are economic to connect, one operating mine, and the mine development area known as the Ring of Fire. At present, only one mine north of Pickle Lake is connected to the transmission grid through a privately owned transmission line.

Figure 2: Map of Northwest Ontario Showing the Existing Transmission System



The North of Dryden sub-region is forecast to experience some of the highest growth in electrical demand in Ontario. Currently the electricity transmission system serving the area is at capacity and is unable to accommodate demand growth.

Mining sector expansion is the primary driver of electricity demand growth in the area; through the expansion of existing mines and the development of new mines, as well as growth in the industries and communities that support the mining sector. Remote communities in the North of Dryden sub-region are currently supplied by diesel generation, however the draft Remote Community Connection Plan[1] developed jointly by the remote communities and the OPA indicates that there is an economic case for connecting the majority of these communities to Ontario's transmission system. The Remote Community Connection Plan is the OPA's primary planning document for these communities, however, the connection would put additional demand requirements on the local transmission system in the areas of Red Lake and Pickle Lake, which is considered in this IRRP.

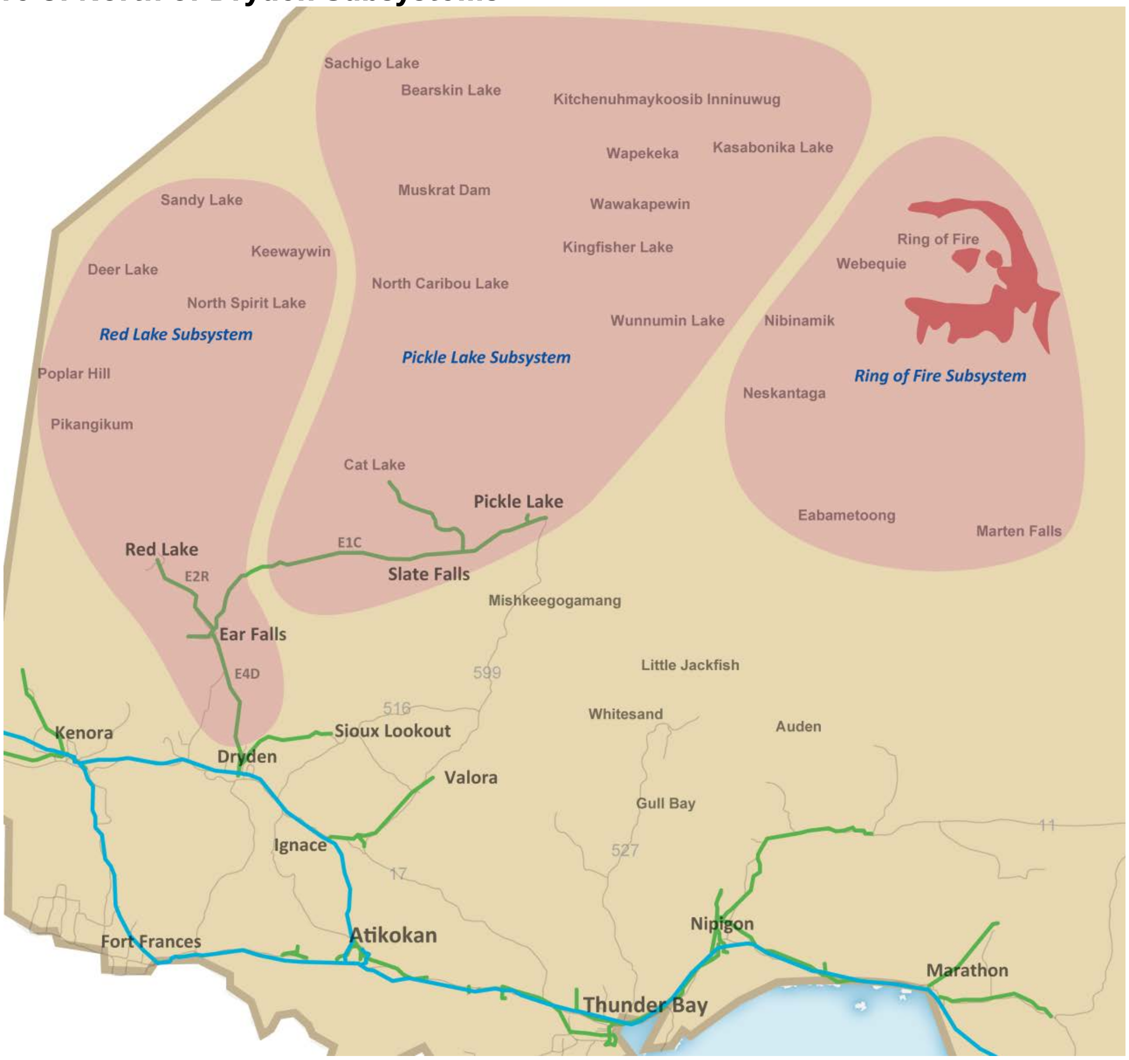
Need Identification

Over the past decade, the annual electricity demand growth in the North of Dryden sub-region has averaged about 1.9%. Growth plans of existing and future customers that are expected to be supplied from the local transmission system indicate that there will be a significant increase in electricity demand over the next 20 or more years.

For study purposes, the area has been segmented into three subsystems generally surrounding Red Lake, Pickle Lake and the Ring of Fire.

[1] A report entitled "Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario" was developed by the Northwest Ontario First Nations Transmission Planning Committee and the OPA. The document can be found at this website:
http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

Figure 3: North of Dryden Subsystems



Where growth in electricity demand identified in these subsystems cannot be met by the existing system, technically feasible conservation, local generation, and transmission options are identified and compared based on their ability to cost effectively meet the needs.

The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information available at the time.

This regional plan has identified that there is a near-term (2014 to 2018) need for additional Load Meeting Capability[2] ("LMC") in the transmission system currently serving the Red Lake and Pickle Lake subsystems. The regional plan has also identified that the majority of the forecasted growth is expected to occur during the medium term between 2019 and 2023. This is the period when remote communities and new mines are expected to develop and connect to the transmission system. The long term is characterized by steadily increasing demand over the remainder of the planning period (to 2033). The need for incremental LMC by subsystem is summarized in Table 1 below.

Table 1: Incremental Capacity Needs by Subsystem

Sub-system	Near-term Capacity Needs (Present to 2018 in MW)			Medium-term Capacity Needs (2019-2023 in MW)			Long-term Capacity Needs (2024-2033 in MW)		
	High	Reference	Low	High	Reference	Low	High	Reference	Low
Pickle Lake	20	18	15	36	28	17	59	47	11
Red Lake	30	30	30	62	44	36	75	48	39
Ring of Fire	22	22	4	67	27	5	73	29	7

Given the magnitude of the increase in electrical demand associated with expanding an existing mine or opening a new mine, as well as growth in electricity demand from growing communities, the area is currently deficient in supply capacity and is expected to become increasingly deficient over the near, medium, and long term.

Options Analysis

The technically feasible options available to meet needs in the Red Lake, Pickle Lake and Ring of Fire subsystems and their implementation timing are outlined in Table 2 below. All costs are net present cost in 2014 dollars, unless stated otherwise (a detailed description of costing methodology can be found in Appendices 10.6, 10.7, and 10.8):

[2] Existing system is thermally limited.

Table 2: Summary of Options

Implementation Timing	Pickle Lake Subsystem	Red Lake Subsystem	Ring of Fire Subsystem
Conservation and DG Options			
Near term and medium to long term (2014-2033)	Customers may investigate opportunities for additional conservation beyond targets and DG resources to suit their own electrical requirements; Industrial Accelerator Program ("IAP"), Aboriginal Conservation Program, Aboriginal Community Energy Plans Program, remote renewable opportunities after grid expanded to supply remote First Nation communities.		
Transmission Options			
Near term (2014-2018)	Build a new 115 kV OR 230 kV transmission line from the Dryden/Ignace area to Pickle Lake **Cost: $80 M - $114 M**	Upgrade existing transmission lines serving Red Lake (E4D and E2R) **Cost: $11 M**	East-West Corridor Option: Build a new 115 kV transmission line from Pickle Lake to Ring of Fire for demand up to 67 MW, or build a new 230 kV line if greater than 67 MW. **Cost: $106 M - $156 M** OR North-South Corridor Option: Build a new 230 kV transmission line from either Marathon or a point east of Nipigon to Ring of Fire **Cost: $175 M**
Medium to long term (2019-2033)		If load in the Red Lake subsystem exceeds 109 MW: Install additional voltage support **Cost: $1 M** If load in the Red Lake subsystem exceeds 130 MW: Build a new 115 kV or 230 kV transmission line between Dryden and Ear Falls **Capital Cost: $91 M - $132 M**[3]	
Generation Options			
Near term (2014-2018)	Gas-fired generator at Pickle Lake fuelled by compressed natural gas, sized and expanded to meet demand growth of up to 31 MW in medium term and up to 76 MW in long	Gas fired generator utilizing up to 30 MW of available gas pipeline capacity at Red Lake **Cost: $51 M**	On-site generation fuelled by compressed natural gas or diesel, **Cost: $209 M - $946 M**[4] Separately connect remote communities
Medium to long term (2019-2033)		Gas-fired generator utilizing up to 30 MW of available gas pipeline	

[3] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of transmission in the long term is $10-15 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[4] Range indicates variation in cost of diesel and compressed natural gas as well as sizing of the generation facility to accommodate the low, reference or high forecast scenarios.

	term **Cost: $158 M - $317 M**	capacity at Red Lake, followed by additional 30 MW at Ear Falls if a new gas pipeline is built **Capital Cost: $95 M - $ 153 M**[5]	**Cost: $ 62 M** **Total Cost: $ 272 M - $1,009 M**

This regional plan considers overall societal costs[6] in determining the least-cost options for supplying the study area. The analysis in this regional plan does not consider the allocation of costs that are attributable to individual customers in the area or how this may affect individual customer decisions on pursuing the societal least-cost options. The final determination of cost allocation between parties will be made through the applicable regulatory process and/or through commercial agreements. For example, cost allocation of transmission and distribution infrastructure is made by the Ontario Energy Board ("OEB"), benefitting customers, and/or transmitters and distributors in the area in accordance with rules set out in the Transmission System Code ("TSC") and Distribution System Code ("DSC").

Summary of Aboriginal, Stakeholder, and Public Feedback

Aboriginal Consultation

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on

[5] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of generation in the long term is $6-8 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[6] Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment, operations and maintenance, fuel, etc.) but excludes the cost of land, taxes and potential impact benefit agreements that may be reached with affected First Nations, which proponents may be required to pay. Governments (and their agencies) undertake projects of infrastructural, environmental or health and safety enhancements in the wider public interest, assessing project merits in terms of the long-term return to current and future generations of society as a whole, using a social discount rate ("SDR"). The OPA uses a four-percent SDR to determine the present value of options over the planning period.

the Draft North of Dryden IRRP. The OPA and Ministry of Energy provided written notice to each community. The OPA also followed up by telephone to each community and sent all presentation material to each community in advance of the sessions.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. The OPA met with Red Sky Métis Independent Nation on June 19, 2014 at Red Sky's office in Thunder Bay.

The OPA was in contact with the Métis Nation of Ontario ("MNO") on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO's member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights.

Municipal Engagement

The OPA met with municipal representatives in person to solicit feedback on the Draft North of Dryden IRRP to be incorporated into the North of Dryden IRRP. The OPA met with municipal representatives from Pickle Lake, Greenstone, Red Lake, Sioux Lookout, Marathon, Dryden and Ignace in December 2013 and February 2014.

Following the municipal engagement meetings, several common themes emerged from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

Written Feedback

Since the posting of the Draft North of Dryden IRRP, the OPA has received written feedback and has followed up with those who contributed written submissions. Written feedback was submitted from the Common Voice Northwest Energy Task Force

("CVNW"), the township of Pickle Lake, Imperium Energy on behalf of the municipality of Greenstone, the Ontario Waterpower Association, Ontario Power Generation ("OPG"), Gold Canyon Resources Inc., Energy Acuity, and an independently represented stakeholder.

In general, written submissions asked clarifying questions regarding the content in the draft report. It should be noted that CVNW submitted a 51-page report of comment covering topics across the entire Northwest. The OPA has considered the input in this report, has met with CVNW since publishing the draft report, and will continue to consider their feedback for regional planning initiatives across northwestern Ontario.

Based on written feedback provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, OPG identified that Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls Switching Station ("SS") associated with the installation of voltage control devices. The OPA has considered this feedback in finalizing the plan.

Webinar

The first draft of the North of Dryden IRRP was posted to the OPA's website in August 2013 and a webinar was held on November 21, 2013 to present the draft IRRP and solicit feedback. Main points of feedback were consistent with that received in written submissions and engagement and consultation meetings.

Recommended Solutions/Actions to be initiated in the near term

The OPA recommends the following solutions for implementation as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem), installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control

devices at Pickle Lake, and transferring the existing load on the line between Ear Falls and Pickle Lake (E1C) to be supplied by this new line;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. Having the Independent Electricity System Operator ("IESO")/OPA initiate discussions with OPG for new reactive power services provided by Manitou Falls Generating Station ("GS") if it is confirmed to be beneficial to the ratepayer.

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long-term forecast scenarios.

The estimated combined present value cost of recommendations (1) and (2) during the planning period is about $124 million[7]. Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

The OPA understands that near-term actions for implementing a new line to Pickle Lake have been initiated by two proponents. Additionally, the OPA understands that Hydro One and various customers in the Red Lake area have initiated discussions to implement the upgrades from Dryden to Red Lake. Implementation of the new 230 kV line to Pickle Lake and the 115 kV line upgrades from Dryden to Red Lake continue to be supported by the OPA.

[7] The August 2013 draft identified this cost as $234-271 million. This change in cost is due to a change in methodology for the NPV economic analysis – treating avoided system generation as a benefit of generation options, rather than a cost to transmission options (as in the 2013 draft). NPV economic analysis is an analysis tool to compare costs over a time horizon, and is not the same as the total project cost for the option being investigated.

Options for the medium to long term period

Pickle Lake Subsystem

The recommendation to build a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake in the near term would be sufficient under all forecast scenarios for the medium to long term.

Red Lake Subsystem

Following the completion of the near-term recommendations, the 130 MW LMC is expected to be sufficient beyond the planning period for the low and reference forecast scenarios, and until 2030 for the high scenario as shown in Table 1. Therefore, the near-term recommendations are expected to be sufficient to meet the needs of the Red Lake subsystem for the long term.

As shown in Table 2, two options have been investigated for the Red Lake subsystem to address any forecasted load in excess of 130 MW. The OPA recommends that these options, incremental natural gas-fired generation at Red Lake and a new transmission line, be retained as viable long term options and re-evaluated in the next planning cycle (1-5 years) for this IRRP. Re-evaluating plans up to every 5 years is consistent with OEB requirements in the TSC, DSC and the OPA license.

Ring of Fire Subsystem

There are several options for supplying the Ring of Fire subsystem depending on the load growth scenario. The analysis indicates that the Ring of Fire subsystem can be cost-effectively served by a 115 kV transmission connection from Pickle Lake (serving five remote communities and mines at the Ring of Fire), if demand over the long term is 67 MW or less. If demand is reasonably certain to exceed 67 MW in the subsystem, a 230 kV transmission line utilizing an East-West corridor from Pickle Lake, or a 230 kV transmission line utilizing a North-South corridor from either Marathon or east of Lake Nipigon would be required, where these alternatives have approximately equal cost.

The 230 kV transmission options are also expected to be more cost-effective from a societal perspective than the combined cost of developing local generation to serve the total mining load and separately connecting remote communities to Pickle Lake.

The OPA is aware of ongoing work for infrastructure development for the Ring of Fire. Common infrastructure corridors serving multiple uses provide synergies for cost and environmental approvals, and may reduce environmental impacts. The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

Conservation Options

Recently, the OPA has received new direction[8] from the Minister of Energy pertaining to the framework for conservation programs moving forward. Directives from the Minister of Energy set conservation targets, which Local Distribution Companies ("LDC") will plan to meet through the development of conservation plans and programs for their service area. The spirit of this new direction is to provide more opportunity for LDCs, communities, and industry to participate in conservation initiatives so a broader scope of programs is expected to be tailored to the local needs of the region. For remote communities, conservation opportunities are considered in the Remote Community Connection Plan.

Furthermore, the following programs are available through the OPA to Aboriginal Communities:

- Aboriginal Conservation Program, with the aim to provide customized conservation services designed to help First Nation communities, including remote and northern communities, reduce their electricity use in residential housing, and in commercial and institutional buildings, like stores, schools and

[8] *2015-2020 Conservation First Framework (March 31, 2014), Continuance of the OPA's Demand Response Program under IESO management (March 31, 2014), and Industrial Accelerator Program (July 25, 2014).*

band offices. This program will be offered for one additional year (ending December 31, 2015) until such time as LDCs are able to develop a CDM program which recognizes the specific requirements of on-reserve First Nation communities as per the 2015-2020 Conservation First Framework Directive.

- Aboriginal Community Energy Plans program to support Aboriginal participation in Ontario’s energy sector by providing up to $90,000 per community in funding to First Nation or Métis communities for local energy planning activities, with remote communities being eligible for an additional $5,000.

Electricity demand of the industrial sector is quite significant in this area. The Industrial Accelerator Program (“IAP”) is available to industrial customers as a means of achieving conservation savings with financial assistance from the OPA.

Given the large component of industrial demand and number of First Nation and Métis communities in the area, the above mentioned programs should be pursued.

Generation Options for the Medium- to Long-term Period

On May 30, 2014, the OPA closed submissions for the Northwest Ontario Request for Information (“NW RFI”). The purpose of the NW RFI was to gather information on the potential availability of diverse resource options in northwestern Ontario, with particular focus on the interim period to 2020. As part of the NW RFI, the OPA received submissions totaling over 4000 MW for the entire Northwest region. Of the over 4000 MW, a few potential projects were identified in the North of Dryden sub-region and were consistent with the generation options investigated as part of this IRRP.

Procurement of generation is not recommended to be pursued at this time for meeting needs in the North of Dryden sub-region. However, if a generation solution is required for other areas of the Northwest, local benefits of these options to the North of Dryden sub-region will be re-evaluated.

2 INTRODUCTION

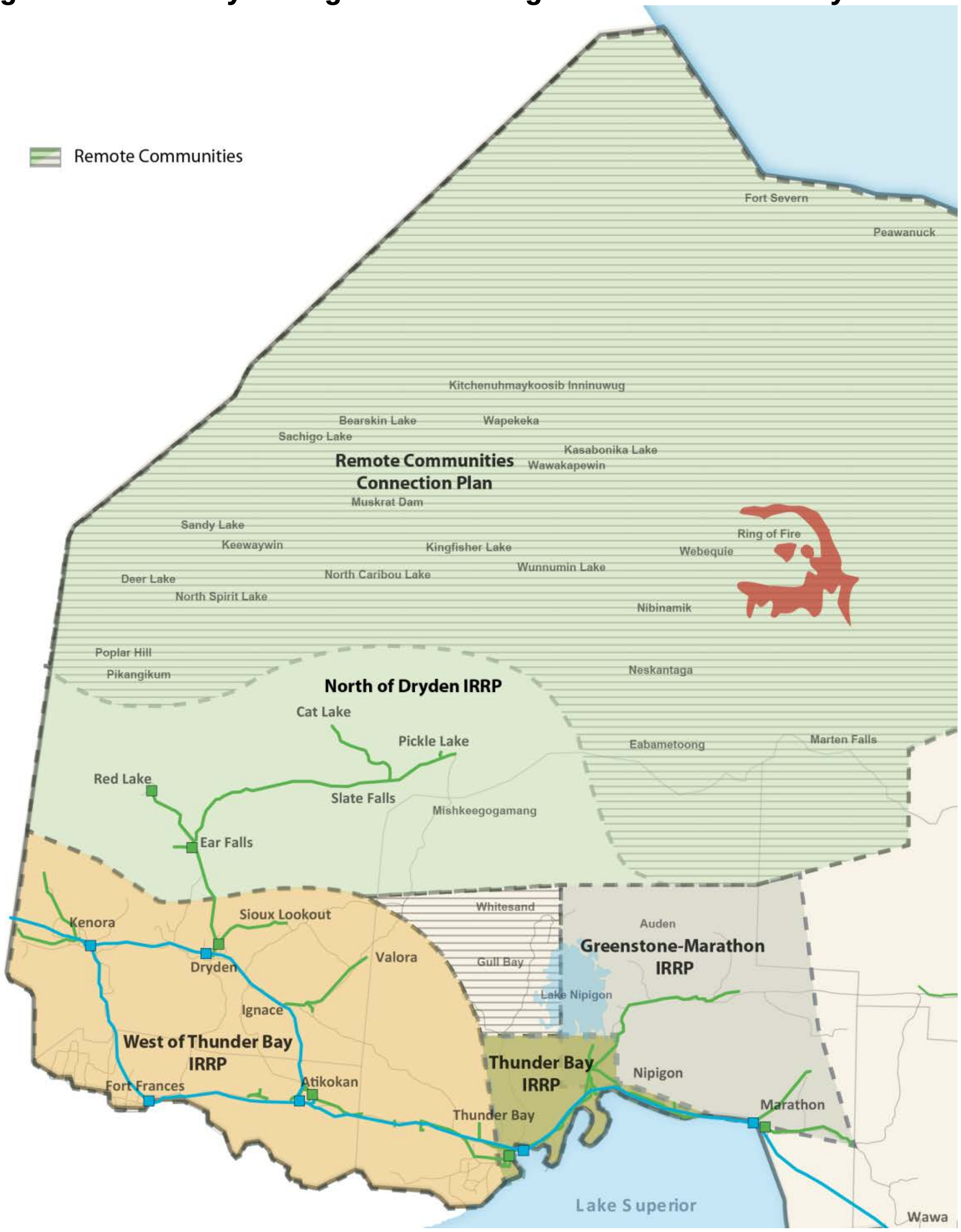
2.1 The North of Dryden Sub-Region

The North of Dryden Integrated Regional Resource Plan ("IRRP") is one of several electricity planning initiatives that the Ontario Power Authority ("OPA") is undertaking for the Northwest Ontario region. Figure 4 identifies the IRRP initiatives currently being undertaken by the OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region.

The Thunder Bay IRRP, West of Thunder Bay IRRP and Greenstone-Marathon IRRP were initiated fall 2014. A Scoping Outcome Assessment Outcome Report for northwestern Ontario, which includes the Terms of Reference for three new IRRPs, is available on the OPA's website, consistent with Ontario Energy Board ("OEB") requirements. The Terms of Reference for the West of Thunder Bay IRRP and the Greenstone-Marathon IRRP include considerations for relationships with the North of Dryden IRRP.

The North of Dryden sub-region is a natural resource rich area in northwestern Ontario, with existing mining, forestry, and hydroelectric generation operations, as well as potential for substantial new resource development. Mining sector expansion, including expansion of existing mines as well as the development of new mines, is a major driver for electricity demand growth in the area, both at mine sites and through growth in industries that support the mining sector. Another major driver for electricity demand growth in the area is the economic connection of remote First Nations communities ("remote communities") to the provincial transmission grid, which are currently served by isolated diesel generation systems.

Figure 4: Summary of Regional Planning Initiatives Underway in Northwest Ontario



The transmission system supplying the North of Dryden sub-region is currently at capacity. This IRRP recommends options to provide new high voltage electrical capacity to meet near-term growth, while providing options to meet future growth as it becomes more certain. These near-term recommendations are presented as action items for immediate or early deployment. Options to address potential longer-term needs are also identified, but the OPA does not make a recommendation on a preferred option at this time, as the longer term still remains uncertain and adequate time is available to continue to monitor the situation closely. The OPA will continue to monitor demand growth and reevaluate longer-term options in future planning cycles for the North of Dryden sub-region. When a decision for the longer-term is required, the OPA will make a recommendation for solutions to be implemented.

The North of Dryden sub-region (shown in more detail in Figure 5) is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario ("MNO"). The southern portion of the area (as shown in Figure 5) is currently served by Ontario's transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest, and Pickle Lake to the northeast. Current mining activity is mostly contained in this portion of the area, and broadly focused around the Towns of Ear Falls, Red Lake and Pickle Lake.

The northern portion of the North of Dryden sub-region (as shown in Figure 5) is comprised of 21 remote communities, one operating mine and the mine development area in the Hudson Bay lowlands known as the Ring of Fire. At present, the mine north of Pickle Lake is connected to the transmission grid by a privately owned transmission line. There are 25 remote First Nations communities that are distant from the existing provincial transmission system and are currently supplied electricity by local diesel generation facilities. On August 21, 2014, an updated draft Remote Community Connection Plan was made available on the OPA website.[9] The Remote Community Connection Plan demonstrates a business case to connect 21 of 25 remote communities that currently rely on diesel generation, to the provincial transmission grid. The business case is based on the avoided cost of diesel fuel. For the purpose of this regional plan, 21 of the 25 communities are assumed to connect to Ontario's transmission system as per the OPA's Remote Community Connection Plan. Communities are expected to begin connecting in the early 2020s.

[9] http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

Figure 5: Map of Northwest Ontario Showing the Existing Transmission System

Distribution connected customers in the North of Dryden sub-region are served by Hydro One's distribution system. There are also a number of large industrial customers that are connected directly to the transmission system in the area and served by Hydro One's transmission system.

2.2 Purpose and Scope of the IRRP

This regional plan assesses the near-term and medium- to long-term electricity supply needs of the North of Dryden sub-region and identifies the options which are available to address these needs in a cost-effective, reliable, and timely manner. The regional plan is intended to identify alternatives and recommended options to local customers, proponents, and local government so development work may proceed. Proponents may also choose to use this regional plan to support the regulatory proceedings they will undertake to seek approval for their projects.

Regional planning for the North of Dryden sub-region began before the OEB's formalized regional planning process was developed as part of the Renewed Regulatory Framework for Electricity ("RRFE"). Consequentially the North of Dryden IRRP does not have a corresponding Scoping Assessment Outcome Report. The North of Dryden IRRP is considered a "transition plan" as per the Planning Process Working Group ("PPWG") report on Regional Planning to the OEB. This version of the North of Dryden IRRP has transitioned and aligned with OEB requirements for the IRRPs as per the OPA's license.

In 2010, the OPA, Hydro One and the Independent Electricity System Operator ("IESO") began working together to assess the ability of the electricity system in the North of Dryden sub-region to meet forecast growth over the near, medium and long term, and to develop integrated plans to address needs that have been identified. Since beginning this planning work, the OPA has engaged existing and potential customers in the area to identify the size and scope of their future electricity needs in the North of Dryden sub-region. The IESO has also completed a number of System Impact Assessments ("SIAs") and feasibility studies for customers requesting additional capacity.

In addition to the regional planning requirements outlined by the OEB, the Minister of Energy identified in the 2010 Long-Term Energy Plan ("LTEP") that the OPA would develop plans to enable the connection of remote First Nations communities, and identified the development of a new transmission line to Pickle Lake to be a priority transmission project, with the scope and timing to be determined by OPA. In February 2011, the OPA received an updated Supply Mix Directive ("SMD") from the Minister of Energy. The updated SMD requires that the OPA develop a plan to connect remote First Nation communities north of Pickle Lake. In December 2013, the Ministry of

Energy released the second LTEP which reiterated that connecting remote First Nation communities in northwestern Ontario is a priority.

Since 2009, the OPA has been working with remote First Nations communities through the Northwestern Ontario First Nation Transmission Planning Committee ("NWOFNTPC") to identify communities that are economic to connect to the provincial transmission system. Through this partnership, planning is underway for connecting most of these communities to the grid and for developing local solutions for the remaining communities to cost-effectively reduce their reliance on diesel fueled generation.

The North of Dryden IRRP is affected by connection of remote communities in two primary ways:

1. The transmission facilities serving the area must be capable of supplying the electrical demand resulting from the connection of these remote communities; and

2. Options for coordinating connection with mining developments, especially in the Ring of Fire area, must be investigated in accordance with assumptions in the Remote Community Connection Plan.

As new information on the connection of the remote communities becomes available, the North of Dryden IRRP will be updated accordingly and consistent with the regional planning process and PPWG report.

It should also be noted that regional plans consider overall societal costs[10] in determining the least cost options for supplying a study area. This analysis does not

[10]Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment etc, operating and maintenance, fuel etc.), but excludes the cost of land, taxes, and potential Impact Benefit Agreements that may be reached with affected First Nations, which proponents may be required to pay. cont'd...

consider how the allocation of costs attributable to individual customers in the area may affect their decision to pursue the societal least cost options. The final determination of cost allocation between parties will be determined by the appropriate regulatory process or commercial agreement. For example, cost allocation of transmission and distribution infrastructure is made by the OEB, benefitting customers, and/or transmitters and distributors in the area in accordance with the rules set out in the Transmission System Code ("TSC") and Distribution System Code ("DSC").

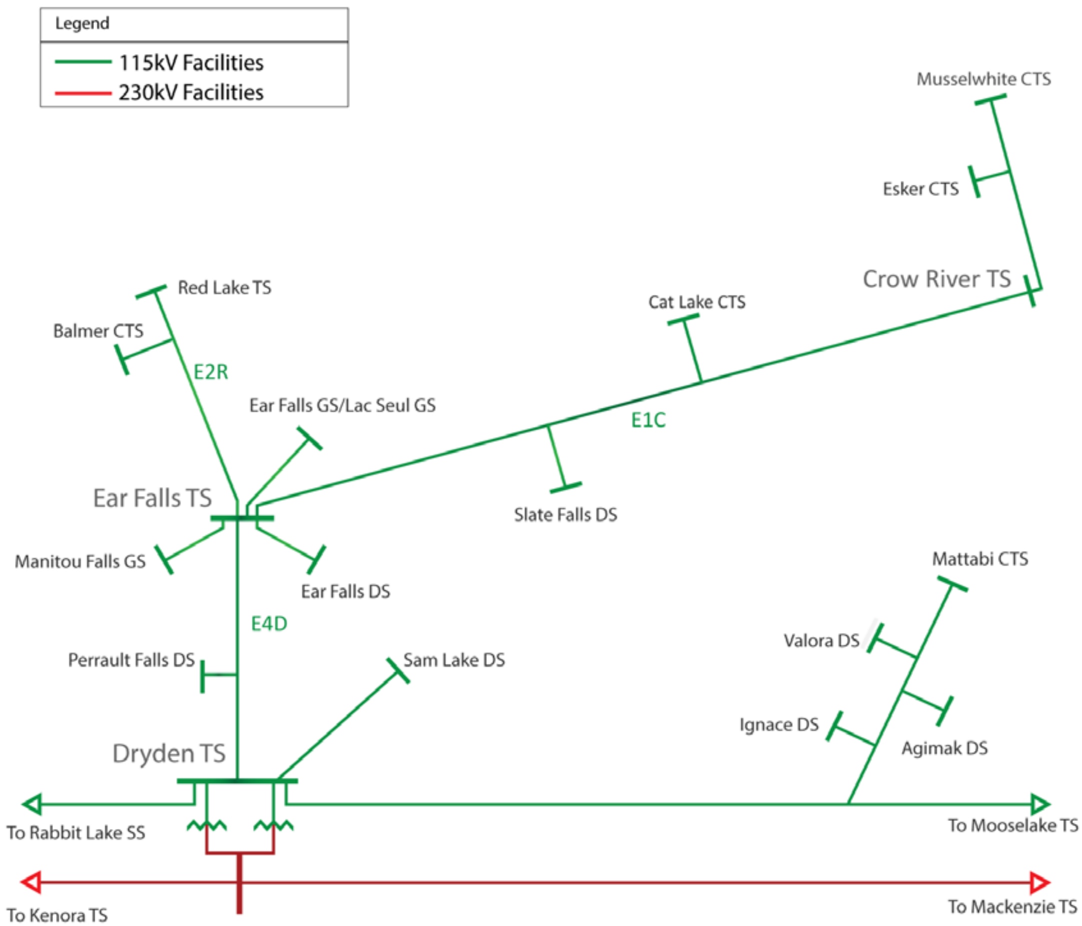
Other planning activities for the region will consider supply needs to the Dryden area for supply of expected load growth in the North of Dryden sub-region. Some of the planning and development work that is underway to ensure an adequate supply is available in the overall Northwest region includes development work being undertaken by NextBridge Infrastructure for an expanded East-West Tie ("EWT"), the May 30, 2014 Northwest Request for Information ("NW-RFI"), and the regional planning initiatives summarized in Figure 4.

...Governments (and their agencies) undertake (or mandate) projects of infrastructural, environmental, or health and safety enhancement in the wider public interest, assessing project merit in terms of the long-term return to current and future generations of society as a whole, using a Real Social Discount Rate (Real "SDR"). The OPA uses a 4% Real Social Discount Rate for determining the present value of options over the planning period.

3 NORTH OF DRYDEN TRANSMISSION AND GENERATION FACILITIES

Currently, electricity customers in the North of Dryden sub-region are supplied by a single-circuit 115 kV radial transmission line ("E4D") emanating from Dryden TS and by local hydroelectric generation. Dryden TS is a major supply station for this area, where the voltage is stepped down from the regional 230 kV system to 115 kV to serve local community and industrial customers as shown in Figure 6 below.

Figure 6 Existing North of Dryden Transmission System



At Ear Falls TS, the 115 kV supply branches to the north, east, and west to supply customers and incorporate generation in the area. Hydroelectric generation is connected to the transmission system at Ear Falls generating station (“GS”) (17 MW Ear Falls + 12.1 MW Lac Seul) and at Manitou Falls GS (73.1 MW). To the north of Ear Falls, the E2R transmission line (“E2R”) supplies Red Lake area mining and community customers. East of Ear Falls, the E1C transmission line (“E1C”) supplies the Town of Pickle Lake, Cat Lake First Nation, Slate Falls First Nation, Mishkeegogamang First Nation, as well as a mine via a privately-owned 115 kV transmission line (“M1M”).

For the purposes of this regional plan, the North of Dryden sub-region is divided into three main subsystems, as shown in Figure 7, the Pickle Lake subsystem, the Red Lake subsystem, and the Ring of Fire subsystem. At present, the Ring of Fire subsystem has no transmission infrastructure and is not connected to the provincial transmission grid, and the Pickle Lake subsystem is supplied downstream of the Red Lake subsystem from Ear Falls via E1C.

The Pickle Lake subsystem includes all demand planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as a mine north of Pickle Lake and any new customers that may connect in the Pickle Lake area in the future. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are identified to connect to Pickle Lake in the 2014 Remote Community Connection Plan.

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities north of Red Lake that are identified as being economic to connect to Red Lake TS in the 2014 Remote Community Connection Plan. As mentioned previously, there is 102.2 MW of hydroelectric generation at Ear Falls GS and Manitou Falls GS.

Figure 7: North of Dryden Subsystems

The Ring of Fire subsystem does not include any existing transmission facilities. The subsystem includes five remote communities that are identified for connection in the 2014 Remote Community Connection Plan as well as potential future industrial customers at the Ring of Fire mine development area.

Due to the current system configuration, when a transmission line in the North of Dryden sub-region is forced out of service all load connected to it is lost. In the event that E4D is removed from service, some of the North of Dryden system can be restored by islanded[11] hydroelectric generation in the Ear Falls area until E4D is returned to service. While the area is islanded from the system and supplied by local generation, the amount of load that can supplied is limited to the available generation output.

Historically, the reliability of electricity supply to some customers in the North of Dryden sub-region has been worse than the average for other customers in northwestern Ontario. Specifically, customers in the Pickle Lake subsystem (currently supplied by E1C) have experienced, on average, 14 unplanned outages per year over the past 10 years.[12] This compares to an average of about three unplanned outages per year for customers served by the other 115 kV lines in northwestern Ontario.[13] Planning for the north of Dryden system includes consideration of this historical performance.

[11] Islanded: when one part of the system is disconnected and operated separately from the rest of the Ontario electricity system.
[12] Hydro One Networks Inc. through correspondence.
[13] Hydro One Networks Inc. through correspondence.

4 HISTORICAL ELECTRICITY DEMAND

4.1 Historical Electricity Demand

Demand for electricity in the North of Dryden sub-region is driven by a number of factors including mining and forestry activity, as well as local community growth. Mining sector expansion is the primary driver of growth in electricity demand in the area. The north of Dryden area is currently winter-peaking. As shown in Figure 8, peak demand in the North of Dryden sub-region has been growing by approximately 1.9% since 2004. Historical demand includes only the Pickle Lake and Red Lake subsystems, since the Ring of Fire subsystem has not yet developed beyond the five remote communities located east of Pickle Lake. Historical demand figures also do not include remote community demand, since they are not currently connected to the provincial transmission system.

Figure 8: North of Dryden Historical Transmission Connected Demand

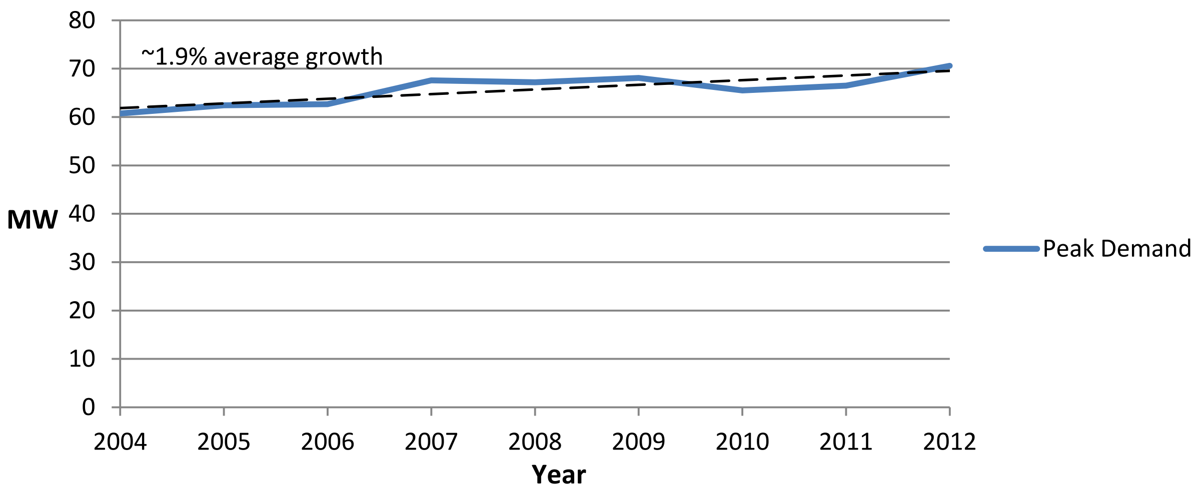
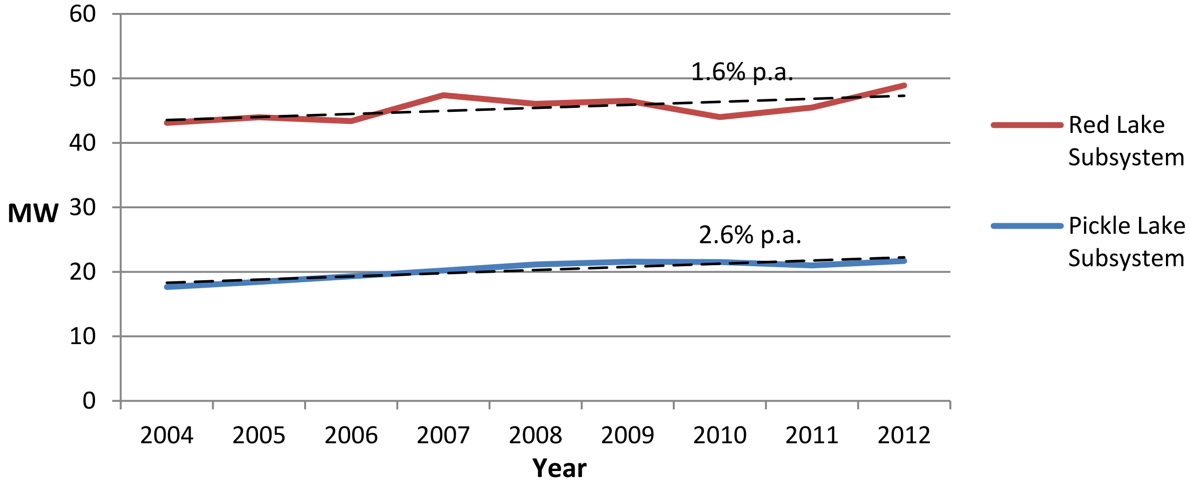


Figure 9 shows that growth in electricity demand has also varied between the Red Lake and Pickle Lake subsystems, with annual growth in electricity demand averaging 1.6% in the Red Lake subsystem and 2.6% in the Pickle Lake subsystem between 2004 and 2012.

Figure 9: North of Dryden Historical Demand by Subsystem



In 2012, 61 MW of capacity was allocated to customers in the Red Lake subsystem, while 24 MW of capacity was allocated to customers supplied in the Pickle Lake subsystem. When the load of the remote communities in each subsystem are added to the connected load, the total load in 2012 increases to 67 MW in the Red Lake subsystem and 31 MW in the Pickle Lake subsystem. At present, no customers in the Ring of Fire subsystem are connected to the provincial grid; however, the combined demand of the five remote communities in the subsystem was about 3 MW in 2012.

4.2 Existing Distributed Generation Resources

Distributed generation is small-scale generation sited close to load centers; it helps supply local energy needs while at the same time contributing to meeting provincial demand. Along with other OPA procurement processes, the introduction of the *Green Energy and Green Economy Act, 2009* and the associated development of the Feed-in Tariff ("FIT") program have encouraged the development of distributed generation resources in Ontario. These procurements take into consideration the system need for generation as well as cost.

Presently, there are five contracted microFIT projects, and one contracted FIT project in the North of Dryden sub-region. All of these projects are located in the Red Lake subsystem. Of these projects, four microFIT solar projects are located in Red Lake with a total contract capacity of 39.3 kW and one microFIT solar project is in Ear Falls with a contract capacity of 10 kW. Analysis of the ability of solar resources in the North of Dryden sub-region to contribute to meeting local demand during the fall months has been estimated to be 5% of contract capacity. Therefore, these units are expected to contribute 2.5 kW to the LMC of the Red Lake subsystem. The FIT project is the Trout Lake River FIT small hydro project, a run of river hydroelectric project near Ear Falls, with a contract capacity of 3.75 MW[14]. The dependable generation level for this project (see Appendix 10.3.2) and its contribution to the LMC of the Red Lake subsystem is assumed to be 0 MW.[15] In total, the contribution of these DG units to the LMC of the Red Lake subsystem is expected to be 2.5 kW (0.0025 MW).

Currently, there are a number of diesel generators that provide backup/emergency supply at mine sites, which are required for health and safety purposes. Generally, these units are not configured for grid connection and thus are not currently available to supply the system. Even if they were configured to connect to the grid, there may be other limitations on their ability to reliably supply load customers on a regular basis including: their age, efficiency, level of emissions, prescribed limits in their operating approvals and their operating and maintenance costs. These units may have some potential to operate as short-term demand management resources, but given the available information they cannot be relied upon to provide the capacity and energy required to meet the needs of the North of Dryden sub-region. Therefore, they have not been considered further in this regional plan.

The Request for Information for Electricity Resources in Northwestern Ontario (“NW-RFI”) was issued to better understand the availability of all potential resources in northwest Ontario including the North of Dryden sub-region, with particular focus on the

[14] Trout Lake River GS, is a contracted FIT small hydro project currently under development, with an expected commercial operation date of Q1 2015.

[15] The performance of the facility during drought conditions has not yet been determined, however, the anticipated contribution based on similar facilities in the area, is much less than the tolerance of the modelling software used for this study.

interim period to 2020. The OPA has received submissions to the NW-RFI. Generation options in this plan have considered the relevant NW-RFI submissions. Should new information become available it will be included at the next update of this regional plan.

5 FORECAST ELECTRICITY DEMAND

To develop the demand forecast the OPA worked with Hydro One (the transmitter and local distribution company serving the North of Dryden sub-region), existing and potential transmission connected industrial customers around Ear Falls, Red Lake, and Pickle Lake[16] and the Ring of Fire, municipalities, business associations, as well as remote First Nations communities in northwest Ontario.

5.1 New Demand from Connection of Remote First Nation Communities

The findings of the Remote Community Connection Plan indicate that due to the high and growing cost of diesel fuel as well as the high cost of operating and maintaining remote diesel generation systems, transmission connection of up to 21 remote communities can avoid substantial future costs of about $1 billion over 40 years and therefore economically justifies the connection of the corresponding 21 remote communities to the provincial transmission grid. For the purposes of this IRRP, it has been assumed that these communities will pursue a connection and therefore includes the demand of the corresponding remote communities in the North of Dryden IRRP forecast. The Remote Community Connection Plan indicates that communities may begin connecting between 2018 and 2020, following the development of required capacity in the North of Dryden sub-region transmission system.

5.2 Residential and Commercial Forecasted Demand

The OPA worked with Hydro One to establish the Residential and Commercial component of the demand forecast in the North of Dryden sub-region. The OPA then removed the industrial component of the load that is connected to the distribution system to determine the forecasted residential and commercial forecasted demand. Hydro One Distribution supplies electricity to customers at the following transformer

[16] The load growth is based on information provided to the OPA by Hydro One Networks Inc. and industrial customers in the North of Dryden sub-region. Hydro One provided information relating to existing distribution facilities North of Dryden; this includes existing community loads and some industrial loads. The OPA worked with existing and potential industrial customers to determine their expected near and long-term electricity needs. The forecast has been shared with Common Voice Northwest's Energy Task Force among other interested stakeholders.

stations: Perrault Falls DS, Ear Falls DS, Red Lake TS, Crow River DS, and Slate Falls DS. Cat Lake CTS is owned by Cat Lake Power Utility Ltd., and is supplied by Hydro One's transmission system from circuit E1C.

5.3 New and Expanding Mining Projects

The majority of forecasted demand growth in the North of Dryden sub-region is anticipated to be primarily driven by the mining sector.

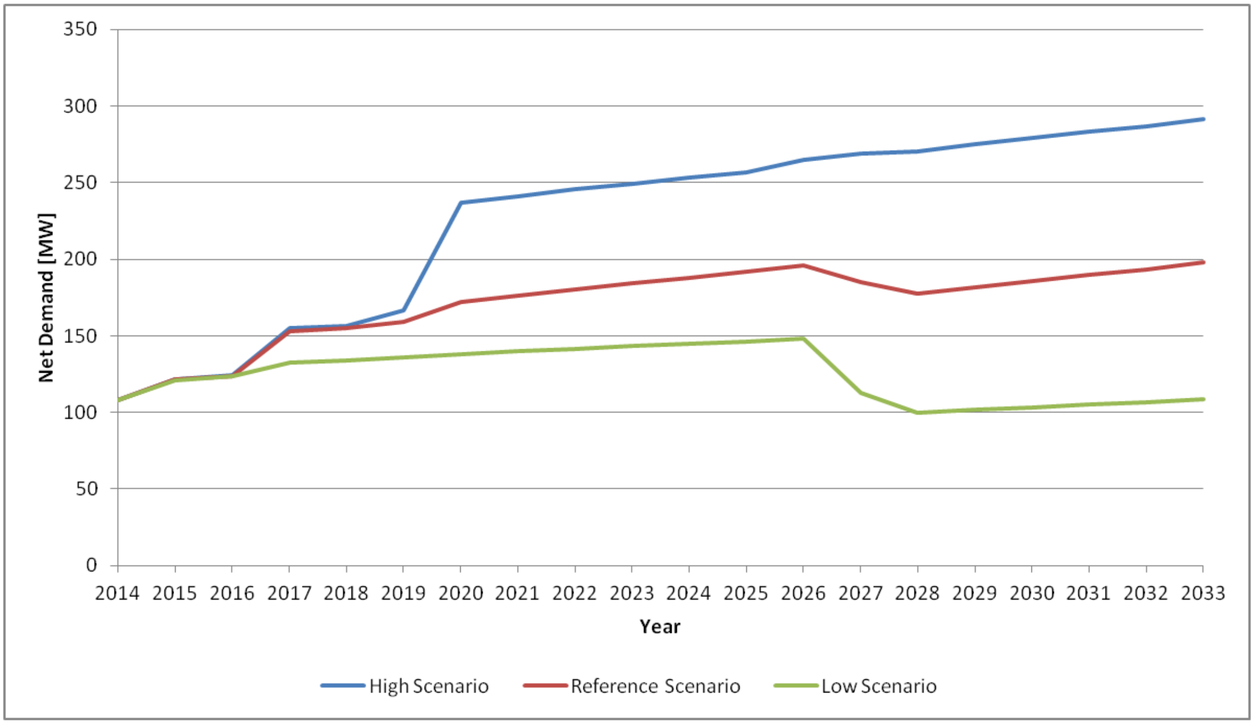
Numerous projects have been proposed in the region, representing a variety of mineral resources, stages of feasibility and development and potential environmental impacts. As mining is a commodity-based industry, there is uncertainty with the timing of mining projects, especially those that are in the relatively early stages of development. This corresponds to uncertainty in the forecasted electrical demand for the area. Recognizing the risk associated with uncertainty in the forecasted demand, the OPA produced three load scenarios. The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information presently available.

Through engagement with the mining companies, mining associations and other stakeholders in the region, and by reviewing available technical documents produced by the mining companies regarding their proposed projects, the OPA categorized projects according to the likelihood that they will be developed within their proposed timelines. The projects have been categorized based on several factors, including:

- Stage of development (e.g. under construction, undergoing an Environmental Assessment ("EA"), still in exploration, etc.)
- Financial feasibility (e.g. results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g. commodity prices, customers and demand)

Figure 10 shows the forecast range over the planning period.

Figure 10: North of Dryden sub-region Net Demand Forecast

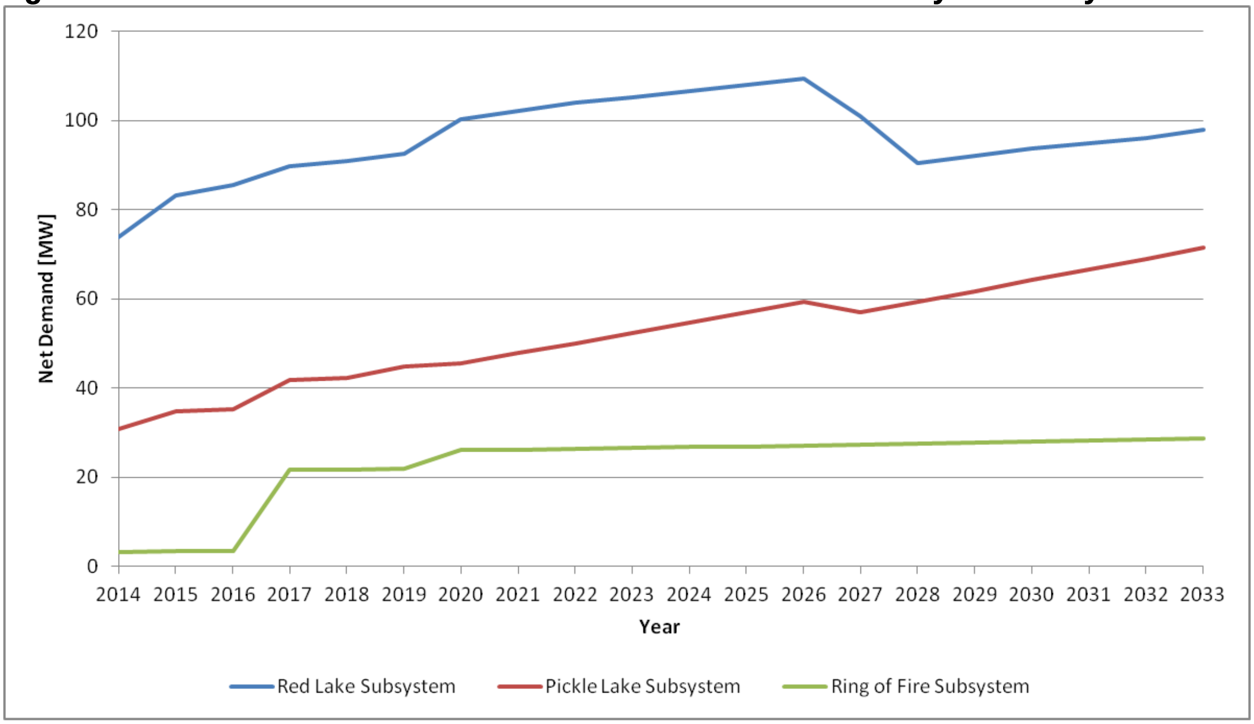


The following descriptions provide the scope of regional activity under the three scenarios.

5.4 Reference Scenario Demand Forecast

Under this scenario, it is assumed that projects currently under construction will be completed and commissioned on schedule. It is assumed that projects with high grade mineral deposits and positive economic assessments will be developed by the timelines specified in their project descriptions with relatively high probability. Projects with potential for extensive environmental impacts are assumed to be unlikely to proceed in the near term as well as projects which are still in the exploration phase. Furthermore, the reference scenario assumes that modest electrical demand driven by the mining sector in the Ring of Fire area is likely to appear before 2024.

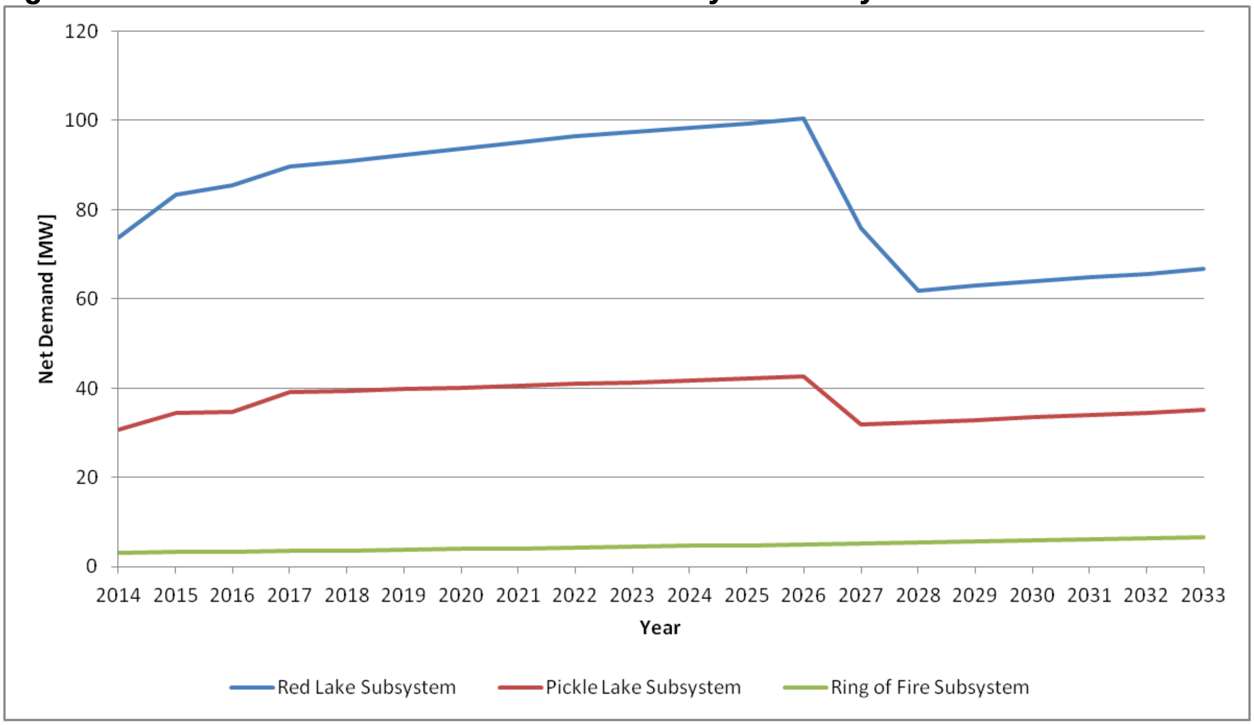
Figure 11: Reference Scenario Demand Forecast for North of Dryden Subsystems



5.5 Low Scenario Demand Forecast

This scenario assumes only the most mature and developed projects (e.g. currently under construction or applying for a leave to construct) are likely to be developed before 2024. It is assumed that other projects with a positive economic assessment will be fully developed with a 50% probability. Early stage exploration projects and projects with marginal economics or environmental, infrastructure and/or accessibility hurdles are assumed to not be developed. This scenario also assumes the Ring of Fire will not be developed before 2034.

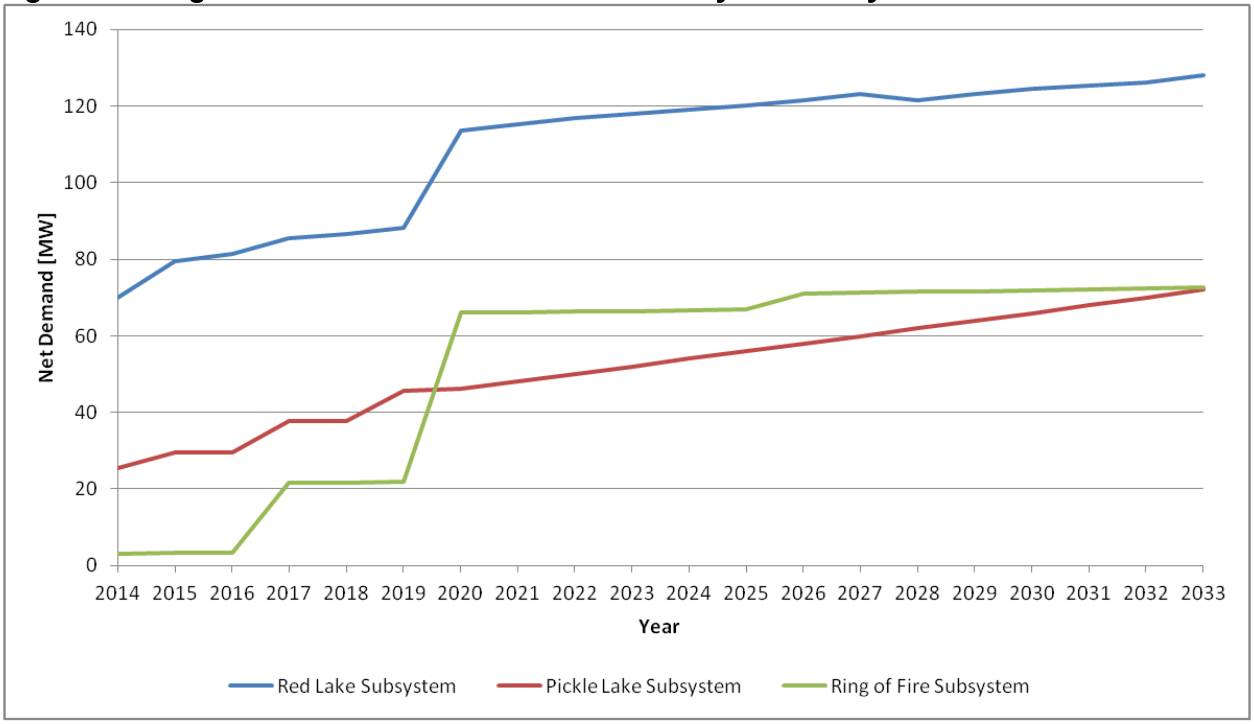
Figure 12: Low Demand Forecast for North of Dryden Subsystems



5.6 High Scenario Demand Forecast

Under the high scenario, most proposed projects are considered likely to be developed and commissioned in the near term. This scenario assumes sufficiently high commodity prices will provide financial feasibility to many projects that may otherwise be considered marginal or uneconomic. The high scenario also assumes an extensive, near- to medium-term build out of the Ring of Fire area, and that multiple mines will be operating in the region by 2020. The expansion of the mining sector is assumed to result in additional expansion of the residential sector in the region, which is also captured in this scenario.

Figure 13: High Demand Forecast for North of Dryden Subsystems



The OPA will continue to monitor electricity demand growth and work with existing and potential customers to maintain up to date electrical demand forecasts for the area. This information will be used to develop regular updates to the North of Dryden IRRP as per the formalized OEB Regional Planning Process.

5.7 North of Dryden Sub-Region Net Electricity Demand

A summary of the net demand forecast scenarios for the North of Dryden sub-region is presented in Table 3.

Table 3: Detailed Net Demand Forecast[17]

NET FORECAST [MW]

Red Lake Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	74	83	85	90	91	93	118	120	122	123	125	126	127	129	128	130	131	133	134	136
Reference Scenario	74	83	85	90	91	93	100	102	104	105	107	108	109	101	90	92	94	95	96	98
Low Scenario	74	83	85	90	91	92	94	95	96	97	98	99	100	76	62	63	64	65	66	67

Pickle Lake Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	31	35	35	44	44	52	53	55	57	60	62	64	66	69	71	73	76	78	81	83
Reference Scenario	31	35	35	42	42	45	46	48	50	52	55	57	59	57	59	62	64	67	69	71
Low Scenario	31	34	35	39	39	40	40	41	41	41	42	42	43	32	32	33	33	34	35	35

Ring of Fire Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	3	3	3	22	22	22	66	66	66	67	67	67	71	71	71	72	72	72	72	73
Reference Scenario	3	3	3	22	22	22	26	26	26	27	27	27	27	27	27	28	28	28	28	29
Low Scenario	3	3	3	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	7

[17] Source: OPA developed forecast as described above. Also includes forecasted values provided by Hydro One.

6 NEEDS IN THE NORTH OF DRYDEN SUB-REGION

Planning for the reliable supply of electricity requires anticipating potential equipment outages before they occur and designing a power system that limits the impacts to consumers, based on good utility practices as outlined in the OEB's TSC. This is accomplished through the application of planning criteria. In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC")[18].

In accordance with ORTAC, the transmission system shall have sufficient capability under peak demand conditions to withstand specific outages while keeping voltages, and equipment loading within applicable limits. The maximum demand that can be supplied by an electricity system in a defined area is known as the load meeting capability ("LMC") of that area. Where an area is served by a single transmission line and local generation, the LMC is determined as the capability of the transmission line during normal operation, with the dependable level of local generation respecting the loss of the largest generating unit. If the area is served by a single transmission line without local generation, the LMC is determined as the capability of the transmission line during normal operation since the loss of the single line will result in the total loss of all connected load. The following factors are considered when determining the LMC of a transmission system serving an area:

- the configuration of the system;
- the capabilities of individual elements comprising the system, for the north of Dryden system, this includes the limits of the transmission lines and the dependable levels of hydroelectric generation;[19] and

[18] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

[19] the dependable level of the existing run of river hydroelectric generation (that is available during drought water flow conditions) is assumed to be available. Details regarding the method for determining the dependable level of hydroelectric and other renewable generation resources for the IRRP are provided in Appendix 10.3.2. Drought conditions are expected to occur about one year in every 10 years and can persist for several months at a time, when watersheds are at their lowest levels in the late summer, fall and early winter months.

- the distribution of demand in the area being supplied.

In general, the greater the distance a given electrical load is located from the inter-regional transmission system (bulk system) supply point (Dryden and/or Marathon or east of Nipigon), the lower the LMC of the system will be. This is due to losses and the need to maintain system voltages within criteria.

6.1 Capability of the Existing North of Dryden System to Supply Forecast Electricity Demand

At present the entire North of Dryden system is supplied from Dryden TS (via E4D) and supported by hydroelectric generation at Ear Falls. The application of ORTAC to the 115 kV transmission system serving the North of Dryden results in an LMC of 85 MW, based on the current line ratings and available dependable hydroelectric generation resources in the Ear Falls area. Existing customers have been allocated 85 MW of capacity on the system and thus the area has reached its capacity limit or LMC. Of this LMC, 24 MW is allocated to the Pickle Lake subsystem and the remaining 61 MW serves the Red Lake subsystem. Mining load in the Ring of Fire subsystem has yet to develop, and the five remote communities in the subsystem are currently supplied by isolated diesel generation. Since the Remote Community Connection Plan identifies that it is economic to connect these communities and there is currently no transmission system serving the Ring of Fire subsystem, the corresponding LMC of the existing provincial power system is 0 MW.

For new customer load to be connected and served in any of the subsystems, additional supply capacity is required. The new capacity needed in order to meet forecast demand growth as provided by Hydro One Distribution, existing and future industrial customers, and the Remote Community Connection Plan (net of planned conservation), is summarized in Table 4 below.

Table 4: Summary of Capacity Needs to Meet the Net Demand Forecast for each Subsystem

Red Lake Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
High Scenario	74	83	85	90	91	93	118	120	122	123	125	126	127	129	128	130	131	133	134	136
Need - High Scenario	*13*	*22*	*24*	*29*	*30*	*32*	*57*	*59*	*61*	*62*	*64*	*65*	*66*	*68*	*67*	*69*	*70*	*72*	*73*	*75*
Reference Scenario	74	83	85	90	91	93	100	102	104	105	107	108	109	101	90	92	94	95	96	98
Need - Reference Scenario	*13*	*22*	*24*	*29*	*30*	*32*	*39*	*41*	*43*	*44*	*46*	*47*	*48*	*40*	*29*	*31*	*33*	*34*	*35*	*37*
Low Scenario	74	83	85	90	91	92	94	95	96	97	98	99	100	76	62	63	64	65	66	67
Need - Low Scenario	*13*	*22*	*24*	*29*	*30*	*31*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*15*	*0*	*0*	*0*	*0*	*0*	*0*

Pickle Lake Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
High Scenario	31	35	35	44	44	52	53	55	57	60	62	64	66	69	71	73	76	78	81	83
Need - High Scenario	*7*	*11*	*11*	*20*	*20*	*28*	*29*	*31*	*33*	*36*	*38*	*40*	*42*	*45*	*47*	*49*	*52*	*54*	*57*	*59*
Reference Scenario	31	35	35	42	42	45	46	48	50	52	55	57	59	57	59	62	64	67	69	71
Need - Reference Scenario	*7*	*11*	*11*	*18*	*18*	*21*	*22*	*24*	*26*	*28*	*31*	*33*	*35*	*33*	*35*	*38*	*40*	*43*	*45*	*47*
Low Scenario	31	34	35	39	39	40	40	41	41	41	42	42	43	32	32	33	33	34	35	35
Need - Low Scenario	*7*	*10*	*11*	*15*	*15*	*16*	*16*	*17*	*17*	*17*	*18*	*18*	*19*	*0*	*0*	*0*	*9*	*10*	*11*	*11*

Ring of Fire Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Scenario	3	3	3	22	22	22	66	66	66	67	67	67	71	71	71	72	72	72	72	73
Need - High Scenario	*3*	*3*	*3*	*22*	*22*	*22*	*66*	*66*	*66*	*67*	*67*	*67*	*71*	*71*	*71*	*72*	*72*	*72*	*72*	*73*
Reference Scenario	3	3	3	22	22	22	26	26	26	27	27	27	27	27	27	28	28	28	28	29
Need - Reference Scenario	*3*	*3*	*3*	*22*	*22*	*22*	*26*	*26*	*26*	*27*	*27*	*27*	*27*	*27*	*27*	*28*	*28*	*28*	*28*	*29*
Low Scenario	3	3	3	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	7
Need - Low Scenario	*3*	*3*	*3*	*4*	*4*	*4*	*4*	*4*	*4*	*5*	*5*	*5*	*5*	*5*	*5*	*6*	*6*	*6*	*6*	*7*

There is a near-term (present to 2018) need for additional capacity (incremental LMC) in each subsystem. The summary of capacity needs indicates that there will be need for 18 MW and up to 20 MW in the Pickle Lake subsystem, 30 MW in the Red Lake subsystem and 22 MW in the Ring of Fire subsystem in the near term.

The majority of forecast demand growth for the North of Dryden sub-region is expected to occur in the medium-term period between 2019 and 2023. This is the period when remote communities and most new mines are expected to connect their load to the system. The long term is characterized by steadily increasing demand over the remainder of the forecast period (2024 to 2033).

In the medium term, capacity needs in the Pickle Lake subsystem are forecast to be 28 MW and up to 36 MW, and up to 59 MW by the end of the planning period in 2033. In the Red Lake subsystem needs are forecast to be 44 MW and up to 62 MW in the medium term, and up to 75 MW by the end of the planning period in 2033.

The capacity need for the Ring of Fire subsystem, which includes potential mines at the Ring of Fire and the connection of five remote communities east of Pickle Lake, is driven by when and if mines connect to the transmission system. If the mines do not connect, then only the demand of the five remote communities will need to be supplied by the system. This is forecast to be 4 MW at the time of connection and up to 7 MW by the end of the planning period in 2033. If the potential Ring of Fire area mines that are considered in the load forecast develop, the capacity need for the Ring of Fire subsystem is forecast to be up to 73 MW by the end of the planning period.

The near-, medium- and long-term capacity needs of each subsystem are summarized in Table 5 below.

Table 5: Summary of Incremental Capacity Needs by Subsystem[20]

Subsystem	Near-term Capacity Needs (Present to 2018 in MW)			Medium-term Capacity Needs (2019-2023 in MW)			Long-term Capacity Needs (2024-2033 in MW)		
	High	Reference	Low	High	Reference	Low	High	Reference	Low
Pickle Lake	20	18	15	36	28	17	59	47	11
Red Lake	30	30	30	62	44	36	75	48	39
Ring of Fire	22	22	4	67	27	5	73	29	7

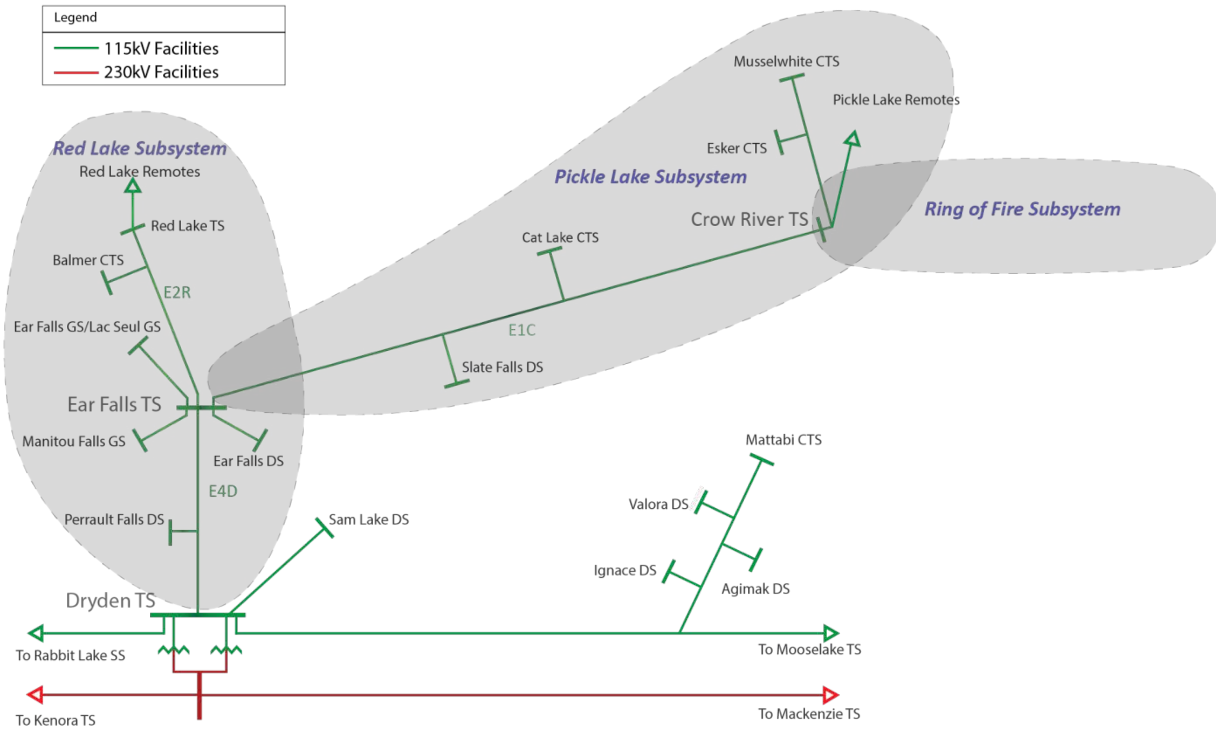
[20] Includes LMC required to supply remote communities that are economic to connect.

6.2 Interdependence between Subsystems

Due to the existing connection of the Pickle Lake subsystem to the Red Lake subsystem at Ear Falls, there is an existing interdependency between these subsystems. Identifying the interrelationships between subsystems is necessary because the supplying subsystem will need to have sufficient capacity to serve the needs of both subsystems. If the Pickle Lake subsystem is supplied completely by a new dedicated transmission connection, then it would be possible (and advantageous during drought conditions) to open the connection between Pickle Lake and Ear Falls (on E1C) and remove this interdependency.

Further, if the Pickle Lake subsystem has sufficient capacity in the future and the Ring of Fire subsystem is connected to Pickle Lake, then a new interdependency between the Pickle Lake and Ring of Fire subsystems would be created. These relationships are highlighted on the map below in Figure 14, which shows the amount of load in the dependent subsystem that is or would be served from the supplying subsystem. The ultimate capacity needed in the Red Lake and Pickle Lake subsystems will depend on the how the Pickle Lake and Ring of Fire subsystems are supplied in the future.

Figure 14: North of Dryden Subsystems and Points of Intersection



7 OPTIONS AND ALTERNATIVE DEVELOPMENT

This section identifies and evaluates options for developing integrated solutions that meet the needs identified in Section 6. Options applicable for all subsystems are described first, subsystem-specific options are then discussed. The options for the Pickle Lake subsystem are then evaluated,[21] followed by those of the Red Lake subsystem and the Ring of Fire subsystem. The options for addressing the needs of the North of Dryden sub-region are divided into those that can meet near-term needs (present-2018) and those which can meet the medium- and long-term needs (2019-2033) for each subsystem. Technically viable options are identified and evaluated in the context of their ability to meet the needs of each subsystem based on cost,[22] ability to meet reliability criteria, incremental capacity enabled, and in-service date.

7.1 Conservation, Renewable and Distributed Generation

Opportunities for Further Cost Effective Conservation in the North of Dryden sub-region

Conservation is important in managing the demand in the North of Dryden sub-region. However, the high levels of load growth anticipated for the sub-region, resulting from connection of new industrial customers and the remote communities require the incorporation of supply-side solutions such as new transmission, distribution and/or generation facilities in the near term. New industrial facilities are assumed to install relatively efficient equipment from the beginning given the inherent economic benefits and the improved codes and standards.

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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	46	35	81	70	46	78
Stage 2: upgrade to 230 kV[35]	136	35	171	160		

[33] Includes demand for Ring of Fire remote communities (7 MW).
[34] Transmission options cannot be developed before 2016.
[35] Upgrade completed in 2023 when three Ring of Fire mines are forecast to be operating

To serve the forecasted electrical demand of the reference scenario to the end of the planning period, without any additional investments, transmission options 2 or 3, a new 230 kV single circuit line to Pickle Lake would be required.

Transmission Option 1, a 115 kV single circuit line to Pickle Lake is insufficient to meet the identified needs of the Pickle Lake subsystem, including connection of up to five remote communities in the Ring of Fire subsystem, for the reference forecast scenario beyond 2030. The reference forecast scenario load exceeds the LMC of a 115 kV single circuit line by 8 MW at the end of the planning period, in 2033.

The OPA recommends that the new line be operated at 230 kV from the onset. Deferring 230 kV operation to when the incremental capacity is required for load supply is not expected to incur any cost savings relative to initially operating at 230 kV. This is due to the fact that some additional voltage control equipment required for 115 kV operation would no longer be required after converting the line to 230 kV operation. This results in a stranded cost which is approximately equal to the deferral value.

Transmission Option 3 is the development of a 230 kV line that is staged to provide additional capacity with deferral of some capital cost to when and if the capacity is needed. This would be done by pre-building the line to 230 kV specifications but initially operating it at 115 kV. When additional capacity is required the line would be reterminated on the bulk 230 kV system on circuit D26A and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake. As indicated above, this option is not expected to result in any relative savings compared to Transmission Option 2.

In order to properly compare costs of transmission options (which also provide incremental capacity to the Red Lake subsystem) to generation options (which do not provide incremental capacity to the Red Lake subsystem) the unit costs consider the total incremental LMC for both the Pickle Lake and Red Lake subsystems that is made available by the option. Table 13 provides a summary of costs and timing for these options.

Table 13: Costs and Timing of Transmission Options

	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[36]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.08 M/MW $0.63 M/MW

From the above tables, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.1.2 Reference Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The Ring of Fire subsystem reference forecasted load from mines and communities is 22 MW in the near term and 29 MW in the medium and long term. Options to supply the Ring of Fire subsystem mines include on-site generation consistent with the Environmental Assessment cases for the mining developments, as well as building a new transmission line utilizing a North-South corridor and originating from either

[36] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Marathon or east of Nipigon, or utilizing an East-West corridor originating from Pickle Lake. Detailed analysis of these options is included in 7.4. As indicated in 6.2, if the Ring of Fire subsystem is supplied from Pickle Lake utilizing an East-West corridor, interdependency between the Pickle Lake subsystem and the Ring of Fire subsystem is introduced.

The following assesses the requirements for supply to the Pickle Lake subsystem under the reference forecast scenario if the mines and communities in the Ring of Fire subsystem are supplied from Pickle Lake. The corresponding LMC required for the Pickle Lake subsystem under this reference scenario is 64 MW in the near term and 100 MW in the medium and long term as indicated by the reference scenario "*Total 2*" in Table 8.

Generation Options

Generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than self-generation options at the mining sites within the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

Transmission Options

The LMC and costs for the respective transmission options are repeated below:

Table 14: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem[1] [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability[37] [MW]	Pickle Lake Subsystem Near term Reference Forecast Demand[27] [MW]	Pickle Lake Subsystem Medium and Long term Reference Forecast Demand[27] [MW]
115 kV line to Pickle Lake[38]	46	35	81	70	64	100
230 kV line to Pickle Lake[28]	136	35	171	160	64	100
Pre-build 230 kV line to Pickle Lake[28] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[39]	46 136	35 35	81 171	70 160	64	100

[37] Includes Ring of Fire subsystem.
[38] Transmission options cannot be developed before 2016.
[39] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Table 15: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake[40]	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[41]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.08 M/MW $0.63 M/MW

From the above tables, and consistent with the analysis in 7.2.1.1, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is the approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution.

This analysis reinforces the need to build a new 230 kV line to Pickle Lake, rather than a new 115 kV line.

7.2.1.3 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 43 MW for the near term, and 48 MW for the medium and long term as indicated by the low scenario "*Total 1*" in Table 8.

[40] Sufficient for near term, insufficient for medium to long term.
[41] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Sensitivity Analysis for Generation Options

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

The remaining 19 MW of LMC for the near term and 24 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 19 MW or 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 38 MW and 47.5 MW would be required, respectively, with a maximum unit size of 9.5 MW (i.e. 4x9.5 MW and 5x9.5 MW).

Table 16: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term Low Forecast Demand[42] [MW]	Medium and Long term Low Forecast Demand[32] [MW]
Near term: 38 MW CNG Generation at Pickle Lake[43]	19	43	43	48
Medium and Long term 47.5 MW CNG Generation at Pickle Lake[33]	28.5	52.5	43	48

Table 17: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
38 MW CNG Generation at Pickle Lake	1-2 Years	$57 M	$131 M	$6.89 M/MW
47.5 MW CNG Generation at Pickle Lake	1-2 Years	$75 M	$158 M	$6.59 M/MW

[42] Includes demand for Ring of Fire remote communities (7 MW).
[43] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

Based on the low forecast demand scenario, the initial near-term generation option does not change. However, less capacity is needed to meet the medium- and long-term needs compared to the reference scenario.

Sensitivity Analysis for Transmission Options

Under the low forecast scenario, the LMC required for the Pickle Lake subsystem is 43 MW in the near term and 48 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 43 MW in the near term and 48 MW in the medium and long term, a new line to Pickle Lake at 115 kV would be required as a minimum and would be the most economic. It should be noted that the low scenario forecast is the only scenario that the 115 kV line option is feasible; the 115 kV line option is not feasible for all other demand scenarios.

Table 18: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term Low Forecast Demand[44] [MW]	Pickle Lake Subsystem Medium and Long term Low Forecast Demand[34] [MW]
115 kV line to Pickle Lake[45]	46	35	81	70	37	41
230 kV line to Pickle Lake[35]	136	35	171	160	37	41
Pre-build 230 kV line to Pickle Lake[35] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[46]	46 136	35 35	81 171	70 160	37	41

[44] Includes demand for Ring of Fire remote communities (7 MW).
[45] Transmission options cannot be developed before 2016.
[46] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Table 19: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	3-5 Years	$126 M	$80 M	$1.31 M/MW
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$2.12 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV[47]	3-5 Years	$155 M	$98 M	$1.85 M/MW

7.2.1.4 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The low scenario does not include any additional load within the planning period from the Ring of Fire area mines compared to 7.2.1.3 and therefore this scenario is identical to 7.2.1.3 and not considered further.

7.2.1.5 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 48 MW for the near term, and 90 MW for the medium and long term as indicated by the high scenario "*Total 1*" in Table 8.

Sensitivity Analysis for Generation Options

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

[47] Stage 2 would not be required for the low forecast scenario without the Ring of Fire

The remaining 24 MW of LMC for the near term and 66 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 47.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 5x9.5 MW). To make available 66 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 85.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 9x9.5 MW).

Table 20: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term High Forecast Demand[48] [MW]	Medium and Long term High Forecast Demand[38] [MW]
Near term: 47.5 MW CNG Generation at Pickle Lake[49]	28.5	52.5	48	90
Medium and Long term: 85.5 MW CNG Generation at Pickle Lake[39]	66.5	90.5	48	90

Table 21: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
47.5 MW CNG Generation at Pickle Lake	1-2 Years	$75 M	$158 M	$6.59 M/MW
85.5 MW CNG Generation at Pickle Lake	1-2 Years	$140 M	$317 M	$4.80 M/MW

[48] Includes demand for Ring of Fire remote communities (7 MW).
[49] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

Sensitivity Analysis for Transmission Options

Under the high forecast scenario, the LMC required for the Pickle Lake subsystem is 48 MW in the near term and 90 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 48 MW in the near term and 90 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required.

Table 22: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term High Forecast Demand[50] [MW]	Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW]
115 kV line to Pickle Lake[51]	46	35	81	70	48	90
230 kV line to Pickle Lake[41]	136	35	171	160	48	90
Pre-build 230 kV line to Pickle Lake[41] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[52]	46 136	35 35	81 171	70 160	48	90

[50] Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem

[51] Transmission options cannot be developed before 2016

[52] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Table 23: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$180 M	$114 M	$1.20 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[53]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.29 M/MW $0.25 M/MW

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is about the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.1.6 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

Under the high scenario forecasted load, the LMC required is 66 MW for the near term, and 156 MW for the medium and long term as indicated by the high scenario "*Total 2*" in Table 8.

[53] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Sensitivity Analysis for Generation Options

Consistent with the reference scenario analysis, generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than generation options from the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

Sensitivity Analysis for Transmission Options

In order to supply 66 MW in the near term and 156 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required. This may be achieved by either Transmission Option 2 or Option 3.

Table 24: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term High Forecast Demand[1] [MW]	Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW]
115 kV line to Pickle Lake[2]	46	35	81	70	66	156
230 kV line to Pickle Lake[2]	136	35	171	160	66	156
Pre-build 230 kV line to Pickle Lake[2] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[3]	46 136	35 35	81 171	70 160	66	156

(1) Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem
(2) Transmission options cannot be developed before 2016
(3) Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Table 25: Costs and Timing of Transmission Options

Options	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$180 M	$114 M	$1.20 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[54]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.29 M/MW $0.25 M/MW

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need, and is only marginally sufficient to meet the near term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium-and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.2 **Pickle Lake Subsystem Recommended Solutions**

The OPA recommends that a new 230 kV single circuit line to Pickle Lake be built as soon as possible in order to meet the needs of the Pickle Lake subsystem. Building the new line to 230 kV standards is the most economic option to meet the reference forecast scenario, which is regarded as the most-likely scenario, and mitigates the long-term risk associated with higher forecasted demand scenarios and maintains the flexibility to supply the Ring of Fire mining development from Pickle Lake. The OPA also recommends that circuit E1C be opened at Ear Falls as an operational measure when

[54] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

the local system is capacity-constrained. This operational measure maximizes the capability of the transmission system in the area, resulting in incremental LMC to the Red Lake subsystem. The capacity constraint is expected to occur during high demand coincident with drought hydroelectric conditions.

It is recommended that development work on a new 230 kV single circuit line to Pickle Lake is completed as soon as possible. The OPA understands that preliminary development work has been started by two First Nations-owned transmission development companies. This work was initiated after the project was identified as a priority transmission project in the Government of Ontario's 2010 and 2013 Long-Term Energy Plans, and was identified for inclusion in future power system plans in the Minister of Energy's 2011 SMD to the OPA.

Implementation of the new line to Pickle Lake continues to be supported by the OPA. The OPA is following the development process for the two development companies closely. The OPA expresses urgency in the need for a new 230 kV single circuit line to Pickle Lake and will support this project to obtain the necessary approvals as soon as possible.

7.3 Summary of Recommended and Assessed Options for Meeting Red Lake Subsystem Needs

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C open at Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA's forecast scenarios, beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and Ontario Power Generation ("OPG"), with assistance from the OPA, negotiate a new contract for amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Table 62 in Appendix 10.6 outlines the cash-flows associated with the circuit upgrades including the station costs being referred to above.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This analysis will consider an updated forecast. The economics of additional gas-fired generation compared to a new transmission line will depend on the amount of load that materializes – gas generation is scalable, while transmission has greater economies of scale if enough demand is present for a sufficient level of utilization. Re-evaluating options in future planning cycles is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

The following section summarizes the analysis and comparison of options.

As mentioned previously, the Red Lake subsystem is currently supplied by the 115 kV line E4D from Dryden TS as well as local run of river hydroelectric generation around Ear Falls. At present the subsystem has reached its LMC. Therefore, forecasted near term growth and medium and long term growth cannot be met by the existing system and other supply options are required. Identified needs for the Red Lake subsystem are summarized in Table 26, below.

Table 26: Needs for Red Lake Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	Reference	High
Near term (2014-2018)	• Supply of mining and community demand in the Red Lake subsystem	91	91	91
	Total Near term	***91***	***91***	***91***
Medium and long term (2019-2033)	• Supply of mining and community demand in the Red Lake subsystem	100	109	136
	Total Medium and Long term	***100***	***109***	***136***

The following near term generation and transmission options have been identified for meeting these needs.

Table 27: Summary of Options to Meet the Near-term Needs of the Red Lake Subsystem

Options to Meet Near-term Needs	Capital Cost	PV Cost	Incremental Load Meeting Capability	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	$89 M	$51 M	30 MW	$1.94 M/MW
Off Load E1C to New Line to Pickle Lake[55]	$66 M	$42 M	35 MW	
Upgrade E4D and E2R	$16 M	$11 M	34 MW	$1.11 M/MW[56]
Off Load E1C to New Line to Pickle Lake	$66 M	$42 M	35 MW	

The OPA recommends upgrading E4D and E2R, as this option has the lowest NPV cost for meeting the near-term needs of the Red Lake subsystem. This option also has the shortest lead time and the highest incremental capacity.

[55] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[56] Note that utilized capacity is 30 MW in the near term.

Table 28: Summary of Options to Meet the Medium- and Long-Term Needs of the Red Lake Subsystem

Options to Meet Medium- and Long-Term Needs	Capital Cost	PV Cost[57]	Incremental Load Meeting Capability	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)[58]	$95 M	$6 M	30 MW	$0.20 M/MW
Ear Falls and Red Lake Gas Generation (60 MW)	$153 M	$8 M	60 MW	$0.13 M/MW
Install Voltage Compensation at Ear Falls and Red Lake (130 MW)	$9 M	$1 M	21 MW	$0.05 M/MW
New 115 kV line to Ear Falls (160 MW)	$91 M	$10 M	30 MW	$0.34 M/MW
New 115 kV line to Ear Falls (190 MW)	$108 M	$12 M	60 MW	$0.20 M/MW
New 230 kV line to Ear Falls (190 MW)	$132 M	$15 M	60 MW	$0.25 M/MW

Once the upgrades to E4D and E2R are complete and the new line to Pickle Lake is in service, the Red Lake subsystem will have an LMC of 130 MW, which is sufficient to meet the supply needs of the Red Lake subsystem for the long term.

Costs do not need to be incurred at this time for additional enhancements for the Red Lake subsystem beyond E4D and E2R upgrades. Under the low scenario and reference scenario (which is considered most likely) no incremental LMC is required beyond 130 MW. Only under the high scenario is incremental LMC forecasted to be required in 2030. The lead times for the long-term incremental options allow for re-evaluation of the demand forecast and options in future planning cycles. Future planning cycles will contain more certainty in the demand forecast as mines and related development materialize. The next planning cycle for the North of Dryden sub-region is between 1-5

[57] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until about 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

[58] Same as the near term option, with install date of 2030 and therefore cannot be combined with the near term option.

years, as per the OEB-sanctioned regional planning process. The prudent course of action for the long term is monitoring load growth and re-evaluating in a timely manner.

7.3.1 **Discussion of Options to Meet the Needs of the Red Lake Subsystem**

Both generation and transmission options are considered for meeting the needs of the Red Lake subsystem.

The following sub-sections will outline the evaluation of various integrated options to meet the near-term and medium-to long-term needs of the Red Lake subsystem for the reference, low, and high load forecast scenarios.

7.3.1.1 Reference Scenario Options Analysis for Red Lake Subsystem

Under the reference scenario, the LMC required is 91 MW for the near term, and 109 MW for the medium and long term as indicated by the reference scenario in Table 26. The existing LMC for the Red Lake subsystem is 61 MW, which is not sufficient.

In establishing the need for incremental LMC for the Red Lake subsystem, it is assumed that, consistent with the recommendations for addressing supply needs for the Pickle Lake subsystem, a new line to Pickle Lake will be implemented and circuit E1C will be operated open at Ear Falls SS. Opening circuit E1C from Ear Falls SS relieves circuit E4D of 35 MW.

Generation Options

At Red Lake, there is a limited supply of natural gas on the existing Union Gas pipeline. This pipeline was extended to serve the needs of an industrial customer at Red Lake and the Town of Red Lake. Based on information provided by the industrial customer, there is sufficient pipeline capacity to increase the LMC by 30 MW from gas-fired generation at Red Lake.

The OPA studied the costs and benefits of implementing gas fired generation to provide incremental LMC in the Red Lake subsystem. The generators could operate both as a local area resource and as a system resource to support growth in northwest Ontario, by reducing loading on the bulk transmission system at Dryden TS. Gas generators in the Red Lake subsystem would be expected to operate for local area needs primarily during periods when run of river hydroelectric generation near Ear Falls is low and when the demand in the area is high.

Due to the availability of gas on the pipeline and the distribution of load in the Red Lake subsystem, gas generation at Red Lake would increase the LMC of the Red Lake subsystem by 30 MW. Table 29 summarizes the capability and Table 30 summarizes the cost and timing associated with the gas generation option.

Table 29: Capacity for Generation Options

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) and Transfer of Pickle Lake load to new line to Pickle Lake	30 MW	91 MW	91	109
	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

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Reference Forecast Demand [MW]	Medium and Long term Reference Forecast Demand [MW]
Near-term Option				
Upgrade E4D and E2R	34	95	91	109
and Transfer of Pickle Lake load to new line to Pickle Lake	35	130		

Upgrading the transfer capability of E4D and E2R and installation of the required amount of voltage control is the recommended solution for the Red Lake subsystem. This option satisfies the reference scenario forecasted demand at the least cost. When E4D and E2R are upgraded and the required amount of voltage control is installed at Ear Falls TS, there will be 95 MW of capacity at Ear Falls TS to serve load in the Red Lake subsystem and 35 MW available to continue to serve the Pickle Lake subsystem. Once a new line to Pickle Lake is implemented and circuit E1C is operated open at Ear Falls SS, an additional 35 MW of LMC is provided to the Red Lake subsystem because currently the Pickle Lake subsystem currently requires 35 MW of supply from Ear Falls to serve 24 MW of load (due to losses). This brings the total LMC for the Red Lake subsystem to 130 MW. The combination of the line upgrades to E4D and E2R as well as a new line to Pickle Lake is expected provide enough LMC for the Red Lake subsystem until the end of the study horizon for the reference forecast scenario.

It should be noted that the incremental LMC of 35 MW provided to the Red Lake subsystem from transferring E1C load to the new line to Pickle Lake requires the E4D and E2R upgrades to be completed. Without the upgrades, E2R would limit the supply into Red Lake because E2R is not relieved from transferring E1C load (E1C transfer only relieves E4D).

This again emphasizes the urgent need to implement both the upgrades to circuits E4D and E2R, as well as the new line to Pickle Lake, as combined these solutions provide a significant increase in LMC for the Red Lake subsystem.

Table 32: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[60]	PV During Planning Period	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	$16 M	$11 M	$1.11 M/MW
Transfer of E1C load to new line to Pickle Lake[61]	3-5 years	$66 M	$42 M	

Based on the above analysis of Generation and Transmission Options for the reference scenario, the upgrading of circuits E4D and E2R in combination with the relief provided by transferring E1C demand to a new line to Pickle Lake is the most economic solution to meet the needs of the Red Lake area. This solution would be sufficient to meet the electrical demand in the Red Lake subsystem until beyond the planning period.

[60] Capital cost does not include the capital cost for new system generation

[61] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

The IESO recently completed SIAs for three customers in the Red Lake subsystem that are interested in increasing their demand on the system. Upgrading of E4D and E2R was also identified by the IESO as the preferred solution to meet the load increase requests. The IESO's analysis is consistent with the OPA's findings.

7.3.1.2 Low Scenario Options Analysis for Red Lake Subsystem

Under the low scenario, the LMC required is 91 MW for the near term, and 100 MW for the medium and long term as indicated by the low scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Red Lake subsystem under the low scenario, the generation option assessed for the reference scenario remains unchanged and is therefore not sensitive to the low scenario demand. A summary of capacity and costs are repeated in the following tables for convenience:

Table 33: Capacity for Generation Options

<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	34	95	91	100
and Transfer of Pickle Lake load to new line to Pickle Lake	35	130		

Table 36: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[63]	PV During Planning Period	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	$16 M	$11 M	$1.36 M/MW
Transfer of E1C load to new line to Pickle Lake[64]	3-5 years	$66 M	$42 M	

[62] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

[63] Capital cost does not include the capital cost for new system generation

[64] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

7.3.1.3 High Scenario Options Analysis for Red Lake Subsystem

Under the high scenario, the LMC required is 91 MW for the near term, and 136 MW for the medium and long term as indicated by the high scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Red Lake subsystem under the high scenario, additional gas generation at Ear Falls or Red Lake would be required in the long term compared to the reference scenario. However, it should be noted that based on information from the existing industrial customer gas pipeline capacity is not available to support gas-fired generation beyond 30 MW.

The option of incremental gas generation has been assessed assuming that industrial customers may require additional natural gas supply to serve their industrial processes.

A summary of capacity and costs are summarized in the following tables:

Table 37: Capacity for Generation Options

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term High Forecast Demand [MW]</th><th>Medium and Long term High Forecast Demand [MW]</th></tr>
<tr><td rowspan="2">Red Lake Gas Generation (30 MW)

and

Transfer of Pickle Lake load to new line to Pickle Lake</td><td>30</td><td>91</td><td rowspan="2">91</td><td rowspan="2">136</td></tr>
<tr><td>35</td><td>126</td></tr>
<tr><td colspan="5">Incremental Long term Options</td></tr>
</table>

Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[65]	30	156	91	136

Table 38: Costs and Timing for Generation Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	2 Years	$89 M	$51 M	$1.36 M/MW
Transfer of E1C load to new line to Pickle Lake[66]	3-5 Years	$66 M	$42 M	
Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[67]	TBD[1]	$95 M[68]	$6 M[69]	$1.00 M/MW

From the above, the option of 30 MW of gas-fired generation at Red Lake using existing pipeline capacity in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake would result in an LMC of 126 MW for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2027 under the high scenario.

The sensitivity analysis does not impact the decisions that are required during this planning cycle. Demand forecasts and long term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Red Lake subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged and

[65] Contingent on new gas pipeline to serve new electricity and gas customers

[66] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

[67] Contingent on new gas pipeline to serve new electricity and gas customers

[68] Capital Cost does not include pipeline costs. It is assumed that if the pipeline was needed anyway, there would be no incremental pipeline costs to incorporate generation

[69] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2026 at earliest, and therefore only 3 years of costs discounted over 13 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

are therefore not sensitive to the high scenario demand. A summary of capacity and costs are repeated in the following tables:

Table 39: Capacity of Transmission Option

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term High Forecast Demand [MW]	Medium and Long term High Forecast Demand [MW]
Near-term Option				
Upgrade E4D and E2R	34	95	91	136
and Transfer of Pickle Lake load to new line to Pickle Lake	35	130		
Incremental Long-term Options				
New 115 kV line to Ear Falls (160 MW LMC)	30	160	91	136
New 115 kV line to Ear Falls (190 MW LMC)	60	190	91	136
New 230 kV line to Ear Falls (190 MW LMC)	60	190	91	136

Table 40: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[70]	PV During Planning Period[71]	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	$16 M	$11 M	$0.78 M/MW
Transfer of Pickle Lake load to new Line at Pickle Lake[72]	3-5 years	$66 M	$42 M	
New 115 kV line to Ear Falls (160 MW LMC)	4-7 years	$91 M	$10 M	$1.72 M/MW
New 115 kV line to Ear Falls (190 MW LMC)	4-7 years	$108 M	$12 M	$2.04 M/MW
New 230 kV line to Ear Falls (190 MW LMC)	4-7 years	$132 M	$15 M	$2.5 M/MW

[70] Capital cost does not include the capital cost for new system generation

[71] Present Value costs for long-term options (i.e. all except E4D and E2R upgrades, and Transfer of Pickle Lake load to new Line at Pickle Lake) consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

[72] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

From the above, upgrading lines E4D and E2R (Dryden to Red Lake) in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake, an LMC of 130 MW would result for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2030 under the high scenario forecasted demand, but not under the reference scenario (which is considered most likely). Incremental transmission options are available if forecasted demand consistent with, or greater than, the high scenario is realized. This is not expected to occur until 2030 under the high scenario and beyond the planning period for the reference scenario. A recommendation for incremental enhancements in addition to the line upgrades and the new line to Pickle Lake does not need to be made at this time. Demand forecasts and long-term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

7.3.2 **Cost Saving Opportunities Utilizing Existing Facilities**

OPG provided information to the OPA on voltage control capabilities of the generating units at Manitou Falls as part of their comments on the Draft North of Dryden IRRP. This information was submitted in writing on November 8th, 2013. Part of this submission indicated that the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power for voltage control during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Total station costs for upgrading E4D and E2R are referenced in Table 62 of Appendix 10.6.

OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is of benefit to the rate payer.

7.3.3 **Red Lake Subsystem Recommended Solutions**

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C normally open at

Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA's forecast scenarios; beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

7.4 Summary of Options to Meet Ring of Fire Subsystem Needs

The Ring of Fire subsystem is a large geographic area on the edge of the Hudson Bay Lowlands approximately 350 km north of Long Lac and approximately 300 km east of Pickle Lake. There are five remote First Nations ("FN") communities in the area (Eabametoong FN, Neskantaga FN, Marten Falls FN, Nibinamik FN and Webequie FN) and a proposed mine development area called the Ring of Fire, where a number of companies are developing mining claims. At present the five remote First Nations communities are supplied electricity by local diesel generators.

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem, including the connection of the remote communities, be coordinated with other infrastructure being investigated or planned, such as transportation corridors to the communities and potential mining development. Mining development companies have indicated different transportation corridor preferences for the Ring of Fire. The OPA understands that a transportation corridor may be developed in an East-West orientation from the Pickle Lake area, or in a North-South orientation from the Nakina area. Transmission options may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or a point east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The OPA has included transmission supply options for the Ring of Fire subsystem that are consistent with these general corridor orientations identified by mining proponents. A shared East-West or North-South transmission corridor, in alignment with a transportation corridor, could be a way to reduce overall cost and environmental impact. Mining development companies have also indicated self-generation as their electrical supply base case in their EA documentation. Consistent with the EA documentation of mining development companies, the OPA has considered self-generation as a possible option for the forecasted mining load in the Ring of Fire subsystem. The decision as to whether the mining load in the Ring of Fire subsystem is supplied by transmission or generation will ultimately lie with the mining companies as they will be the beneficiaries of a direct transmission supply. The OPA has already indicated in the Remote Community Connection plan that there is a business case for connecting the five remote communities in the vicinity of the Ring of Fire on their own merit, without the connection of the mining development. The connection of the mining development with the five remote communities creates a stronger business case for the connection of the remote communities. The OPA will continue to support the economic connection of remote communities.

The relative economics of generation versus transmission to supply mining load in the Ring of Fire subsystem depends on the amount of electrical demand that materializes. The reason for this is because transmission is generally more economic for relatively large electrical demand, while generation is scalable and generally more economic for lower levels of electrical demand. Details of the various options are explained further later in this section.

The OPA also recognizes that there may be potential for further utilization of a North-South transmission supply to the Ring of Fire subsystem through integration with supplying new growth in the Greenstone area. The detailed needs and supply options specific for new growth in the Greenstone area will be assessed as part of the Greenstone-Marathon IRRP, which may be used to supplement the findings in this IRRP.

The needs identified for the Ring of Fire subsystem are to connect the five remote communities to the provincial transmission system and to supply the potential future mines. The connection of the five remote communities cannot be completed until at least 2018, as indicated in the Remote Community Connection Report. Also, mines at the Ring of Fire are not expected to start up until 2017 at the earliest. A summary of the needs is provided in Table 41.

Table 41: Needs for the Ring of Fire Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	Reference	High
Near term (2014-2018)	• Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems	4	22	22
	Total Near term	***4***	***22***	***22***
Medium and long term (2019-2033)	• Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems	7	29	73
	Total Medium and Long term	***7***	***29***	***73***

An assessment developed for the Remote Community Connection Plan determined that up to five remote First Nation communities in the subsystem are economic to connect to the grid (see Appendices 11.2 and 11.4). As a result, all options identified for this subsystem include the connection of the five remote communities included in this subsystem.

Options to meet these requirements include:

- Connection of mines and remote communities to the transmission system; or
- Connection of the remote communities and on-site generation fueled by diesel or natural gas for the mines.

Transmission supply options being considered for the Ring of Fire subsystem include a new supply from Pickle Lake, a point east of Nipigon, or Marathon. These options were developed with the understanding that both East-West and North-South transportation corridors are being considered and linear corridor planning with electricity may provide greater economic efficiencies and reduce environmental impacts. It should also be noted that 230 kV supply to Pickle Lake is the minimum technical requirement for connecting any mining load at the Ring of Fire to Pickle Lake.

Options for supply to the Ring of Fire subsystem are summarized in Table 42 below.

Table 42: Summary of Options to Meet the Medium- and Long-Term Needs of the Ring of Fire Subsystem[73]

	Capital Cost[74]	PV Cost	Utilized Capacity	PV Unit Cost of Utilized Capacity
Diesel Generation + Remote Connection	Low: $186 M High: $277 M	Low: $456 M High:$1,009 M	29 MW 73 MW	$15.7 M/MW $13.8 M/MW
CNG Generation + Remote Connection	Low: $240 M High: $421 M	Low: $272 M High: $480 M	29 MW 73 MW	$9.37 M/MW $6.58 M/MW

[73] Transmission options routed from Pickle Lake include a prorated portion (based on the relative amount of load that would be supplied to each party) of the cost for a new 230 kV transmission line to Pickle Lake.
[74] Description of capital costs can be found in the following tables: Generation, Table 26; Transmission, Table 27

115 kV Line from Pickle Lake to Ring of Fire	$189 M	$106 M	29 MW	$3.64 M/MW
230 kV Line from Pickle Lake to Ring of Fire	$277 M	$156 M	73 MW	$2.14 M/MW
230 kV Line from Marathon to Ring of Fire	$327 M	$175 M	73 MW	$2.40 M/MW
230 kV Line from east of Nipigon to Ring of Fire	$327 M	$175 M	73 MW	$2.40 M/MW

Options that are developed for the scenario that the Ring of Fire subsystem mining developments and remote communities are supplied from a transmission connection to the provincial power system assumes the cost for the transmission option with road access. The option for connecting only the remote communities from a transmission connection to the provincial power system assumes the cost for the transmission option without road access. Road access may be provided from the development of a multi-use corridor.

7.4.1 Discussion of Options to Meet the Needs of the Ring of Fire Subsystem

Currently, the electric supply of the five remote communities in the Ring of Fire subsystem is provided by local diesel generators. As discussed previously, up to five of these communities have been shown to be economic to connect to the transmission system in the Remote Community Connection Plan. Hence, for the purpose of the North of Dryden IRRP, these five communities are assumed to connect to the transmission system.

Given the timelines required to obtain approvals and to design and construct transmission facilities of this scale, the OPA has assumed that transmission options for serving remote communities would not be in service until 2018 at the earliest.

7.4.1.1 Reference Scenario Options Analysis for Ring of Fire Subsystem

Under the reference scenario electrical demand forecast, the LMC required is 22 MW for the near term, and 29 MW for the medium and long term as indicated in Table 41. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

Generation Options

Two Environmental Assessment Terms of Reference published by mining developers in the Ring of Fire have included electricity supply options for on-site generation for their particular mining projects. They have identified that diesel or CNG fueled generation plants can provide sufficient capacity and energy to reliably meet their needs and can be brought into service within their mine development timelines. Assuming that a proposed all-season road would connect the Ring of Fire to the provincial highway system, the transportation of the large volumes of fuel required to operate on-site generation of this scale would be enabled.

As mentioned earlier, the five remote communities in the Ring of Fire subsystem have been identified as economic to connect to the transmission system at Pickle Lake. Should the Ring of Fire mines choose the self–generation option for their electricity needs, it is assumed that the remote communities will connect to Pickle Lake through a separate remote community connection project. This option is discussed in detail in the Remote Community Connection Plan. The cost of serving the remote communities by transmission and the Ring of Fire area mines with on-site generation are considered together as an integrated option for serving the Ring of Fire subsystem.

The OPA evaluated the feasibility and relative economics of various on-site generation options to supply the mining load. Findings indicated that reciprocating engines fueled either by diesel or natural gas could power future mines at the Ring of Fire, which is consistent with the respective EA Terms of Reference of developers. These units are available in a large range of sizes which allows for capacity to be scaled to meet a wide range of needs for individual mines initially and over time. Mine developers at the Ring of Fire have plans for transportation systems that would connect the Ring of Fire to the provincial transportation network, by either road or rail. One of these options is an all-season road from the Ring of Fire to the railway near Nakina. In order to develop cost estimates for this regional plan it is assumed that fuel would be transported to the Ring of Fire via the provincial road network to Nakina and then from Nakina to the Ring of Fire via the proposed all-season road[75].

Supplying diesel fuel to mine sites for power generators is common practice. Diesel fuel can be purchased at a number of bulk storage facilities in northwest Ontario and transported to mine sites. CNG also appears to be feasible though there are no direct examples that the OPA could reference for remote mining applications. The OPA has leveraged available public information and worked with industry to establish a reasonable set of assumptions and inputs that were used to develop cost models for both remote diesel and CNG fueled DG. The cost of fuel transportation infrastructure (trucks and trailers) required to transport both diesel and CNG to the mine sites has been included in the cost analysis.

The infrastructure required to fuel a natural gas generation facility at the Ring of Fire would include a compression station located along the TCPL mainline with road access to the proposed all-season road to the Ring of Fire beginning near Nakina. Due to the complexities and permitting required to build a CNG storage facility at the mine site, the OPA understands that no CNG storage facilities are planned for the mine sites and that fuel would be delivered on a just in time basis, with allowance for only a few trailers to be kept on site. Each trailer stores approximately 2 hours supply of fuel.

While the process is not substantially different from the transport and use of diesel, there are more steps and facilities required to compress, transport and decompress the gas before it can be used. Without significant on-site storage facilities, natural gas transportation logistics will be more challenging particularly during inclement weather when the all-season road may be closed for extended periods. To account for such challenges, it is likely that the generators will have to be capable of using both diesel and natural gas. Mines will have large scale diesel storage on site to fuel their vehicles and heavy equipment which could be used to fuel the generators when natural gas

[75] The OPA does not have expertise in transportation planning; this assumption is solely for developing cost estimates for generation OM&A and does not indicate a preference of the OPA.

supply is interrupted. The OPA has also discussed the results of its CNG cost model with industry to ensure the findings are reasonable.

Liquefied natural gas (“LNG”) may also be a feasible option to fuel generators. However, it is not clear what minimum production volume is required to establish a natural gas liquefaction facility in northwest Ontario or what the economics of such facilities would be. As a result, the OPA does not have sufficient information to assess either the feasibility or the economics of LNG at this time.

Table 43: Generation Options at the Ring of Fire Mines

Options for Mining Load	Mining Generation [MW]	Near term Reference Forecast Demand (Mines Only) [MW]	Medium and Long term Reference Forecast Demand (Mines Only) [MW]
Diesel Generation	22	18	22
CNG Generation	22		

From the above, in order to meet the reference scenario demand for the Ring of Fire mining load, up to 22 MW of diesel or CNG generation are considered.

The costs for supplying the forecasted Ring of Fire subsystem mining load by either 22 MW of diesel or CNG generation at the Ring of Fire mines are summarized in Table 44.

Table 44: Generation Options at the Ring of Fire Mines

Options for Mining Load	Mining Generation [MW]	Initial Capital Cost	Average Annual Fuel and O&M	Total PV
Diesel Generation	22	$72 M	$39 M	$393 M
CNG Generation	22	$127 M	$20 M	$209 M

As discussed above, the integrated options for serving the needs of the remote communities and the mines in the Ring of Fire subsystem includes a transmission connection option to serve the five remote communities from Pickle Lake in the case where the Ring of Fire mines opt for self-generation. This option would consist of a 115 kV transmission line from Pickle Lake to an end point near Webequie FN, passing near Neskantaga FN. Transformer stations to serve the communities would be sited near Neskantaga FN and at the end of the line near Webequie FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would be connected via distribution lines and stations to the transformer station near Neskantaga FN, while Webequie FN and Nibinamik FN would be connected by distribution lines and stations to the transformer station near Webequie FN. Figure 36 in Appendix 11.4 shows this planned connection system for the five remote communities.

The OPA has estimated the cost of connecting the five remote communities in this subsystem to be $64 million, consistent with the 2014 Remote Community Connection Plan. The costs of the integrated options for mine site generation and transmission connection of remote communities are summarized in Table 45.

Table 45 Integrated Options for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake

Integrated Options	PV of Mine Site Generation	PV Remote Connection	Total PV of Integrated Option
Diesel Generation + Remote Connection	$393 M	$62 M	$456M
CNG Generation + Remote Connection	$209 M	$62 M	$272 M

Therefore, in order to supply the entire need for the Ring of Fire subsystem – connection of remote communities and generation supply to mines – a new 115 kV connection for remote communities and 22 MW of generation would be required and would total $273-$457 M, depending on fuel.

Transmission Options

Transmission options for supplying the five remote communities and mining load at the Ring of Fire together include the following:

1. East-West corridor

    a. A new 115 kV single circuit line from Crow River DS or a new station at Pickle Lake to the Ring of Fire

    b. A new 230 kV single circuit line from a new 230/115 kV station at Pickle Lake to the Ring of Fire, and new 230/115 kV TS near Neskantaga FN

2. North-South corridor

    a. A 230 kV single circuit line from Marathon TS to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN

    b. A 230 kV single circuit line from east of Nipigon to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN

The LMC of these options are summarized in Table 46 below

Table 46: Capacity of Transmission Options

Options	Ring of Fire Subsystem Load Meeting Capability [MW]	Ring of Fire Subsystem Near term Reference Forecast Demand [MW]	Ring of Fire Subsystem Medium and Long term Reference Forecast Demand [MW]
East-West corridor			
115 kV line from Pickle Lake	67	22	29
230 kV line from Pickle Lake	78	22	29
North-South corridor			

230 kV line from Marathon TS	78	22	29
230 kV line from east of Nipigon	78	22	29

Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 67 MW of load at the Ring of Fire (60 MW of mining load plus 7 MW of remote community load). Figure 36 in Appendix 11.4 shows a potential configuration of the North of Dryden system with a 115 kV connection to the Ring of Fire from Pickle Lake. This would be sufficient and would be the least-cost option to supply the reference scenario forecasted demand.

It is not economic under the reference scenario forecasted demand to supply the Ring of Fire subsystem by a 230 kV transmission line.

If mining and remote community load exceeds 67 MW a new 115 kV supply would no longer be sufficient and a 230 kV connection to the Ontario transmission system is required for the Ring of Fire subsystem.

The North-South options will be assessed in further detail in the Greenstone-Marathon IRRP by considering possible economic synergies with potential load growth in the Greenstone area.

As mentioned in Section 7.4.1, the five remote communities in the Ring of Fire subsystem have been identified in the Remote Community Connection Plan as being economic to connect on their own. It is therefore assumed that if the Ring of Fire mines do not connect to the grid, then the five remote communities will continue to pursue a connection to the transmission system at Pickle Lake. The lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN.

A summary of the cost and capabilities of these options is provided in Table 47.

Table 47: Capacity and Costs of Transmission Options

Options	Capital Cost	Prorated Capital of Line to Pickle Lake	Total Capital	Total PV During Planning Period
Remote Community Only Connection from Pickle Lake (115 kV)	$101 M	$13 M	$114 M	$62 M
New 115 kV line from Pickle Lake to Ring of Fire	$146 M	$44 M	$189 M	$106 M
New 230 kV line from Pickle Lake to Ring of Fire	$196 M	$35 M	$231 M	$127 M
New 230 kV Line from Marathon to Ring of Fire	$327 M	N/A	$327 M	$175 M
New 230 kV Line from east of Nipigon to Ring of Fire	$327 M	N/A	$327 M	$175 M

The cost responsibility for the new line to Pickle Lake and any connection line to the Ring of Fire shared by mines and remote communities would be determined through commercial agreements and/or through the OEB's Leave to Construct application process.

7.4.1.2 Low Scenario Options Analysis for Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 4 MW for the near term, and 7 MW for the medium and long term as indicated by the low scenario in Table 41. This scenario corresponds to the load associated with only the five remote communities in the Ring of Fire subsystem.

Therefore, under this scenario, only the connection of the five remote communities is considered. As indicated in the previous section, the lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN. This is expected to cost $115 M net-present value over the planning period.

Details are included in the Remote Community Connection Report. This scenario does not require any additional consideration.

7.4.1.3 High Scenario Options Analysis for Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 22 MW for the near term, and 73 MW for the medium and long term as indicated by the high scenario in Table 41. Of the 73 MW, 66 MW is mining load and 7 MW is community load. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the high generation option would be required. The tables outlining the generation options are repeated for convenience:

Table 48: Generation Options at the Ring of Fire

Options for Mining Load	Mining Generation [MW]	Initial Capital Cost	Average Annual Fuel and O&M	Total PV
Diesel Generation	71	$163 M	$102 M	$946 M
CNG Generation	71	$307 M	$46 M	$418 M

Table 49: Integrated Option for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake

Integrated Options	PV of Mine Site Generation	PV Remote Connection	Total PV of Integrated Option
Diesel Generation + Remote Connection	$946 M	$62 M	$1,009 M
CNG Generation + Remote Connection	$393 M	$62 M	$456 M

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged. A summary of capacity and costs are repeated in the following tables for convenience:

Table 50: Capacity of Transmission Options

Options	Ring of Fire Subsystem Load Meeting Capability [MW]	Ring of Fire Subsystem Near term High Forecast Demand [MW]	Ring of Fire Subsystem Medium and Long term High Forecast Demand [MW]
East-West corridor			
115 kV line from Pickle Lake	67	22	73
230 kV line from Pickle Lake	78	22	73
North-South corridor			
230 kV line from Marathon TS	78	22	73
230 kV line from east of Nipigon	78	22	73

Table 51: Capacity and Costs of Transmission Options

Options	Capital Cost	Prorated Capital of Line to Pickle Lake	Total Capital	Total PV During Planning Period
Remote Community Only Connection from Pickle Lake (115 kV)	$101 M	$13 M	$114 M	$62 M
New 115 kV line from Pickle Lake to Ring of Fire	Not Technically Feasible for medium to long term			
New 230 kV line from Pickle Lake to Ring of Fire	$196 M	$35 M	$231 M	$127 M
New 230 kV Line from Marathon to Ring of Fire	$327 M	N/A	$327 M	$175 M
New 230 kV Line from east of Nipigon to Ring of Fire	$327 M	N/A	$327 M	$175 M

As indicated previously, a 115 kV line to the Ring of Fire subsystem could supply up to 67 MW, and a 230 kV line would be required to serve demand greater than 67 MW.

Based on the high demand scenario, a 230 kV supply to the Ring of Fire subsystem would be required. A recommendation for a specific solution is not required at this time. The magnitude and timing of the potential mining load is still very uncertain, and decisions regarding transportation infrastructure to the Ring of Fire have not yet been made. A common corridor to the Ring of Fire should consider the potential need for a transmission line.

7.4.2 **Ring of Fire Subsystem Recommendations**

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem is coordinated with other infrastructure being investigated, such as transportation. Transmission may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The lowest cost option for meeting the medium- and long-term identified needs is a transmission connection from either Pickle Lake, Marathon, or east of Nipigon to the Ring of Fire. The incremental cost of developing a transmission connection capable of serving mines and remote communities is substantially lower than the cost of generation to serve mines and separately connect the remote communities.

8 FEEDBACK FROM ENGAGEMENT AND CONSULTATION

8.1 Aboriginal Consultation

The OPA recognizes the importance of engaging with First Nation and Métis communities and carrying out the procedural aspects of Aboriginal consultation where delegated by the Crown.

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on the Draft North of Dryden IRRP. The Ministry of Energy wrote to each community on the consultation list by letter dated April 25, 2014 to provide notice of the consultation and the delegation of the OPA's role as a delegate of the Crown. The OPA then wrote to each community by letter dated May 26, 2014 to provide the dates and locations of the consultation sessions scheduled for June 2014. The letters included the OPA's commitment to cover the cost of travel and accommodation expenses associated with attending a consultation session. OPA staff then phoned each community to follow up and to answer questions about the North of Dryden IRRP consultation and provided presentation materials in advance of all sessions. The OPA sent additional invitation letters by registered mail on September 26, 2014 for the consultation session that occurred on October 16, 2014. The OPA followed up by phoning each community to ensure that leadership and/or band staff were aware of the North of Dryden consultation.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. Representatives from 15 communities attended the sessions. Two communities informed the OPA that the North of Dryden IRRP is outside their area of interest. Representatives from the Chiefs of Ontario, Grand Council Treaty 3, and Nishnawbe Aski Nation also attended the sessions but did so for informational purposes only. Notes of these sessions were prepared by the OPA and posted in the regional planning section of the OPA’s website.

The OPA was in contact with the Métis Nation of Ontario (“MNO”) on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO’s member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

The OPA met with Red Sky Métis Independent Nation on June 19 at Red Sky’s office in Thunder Bay. OPA staff delivered a presentation on the North of Dryden IRRP and answered questions posed by Red Sky’s representatives.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights. Some clarifying questions were asked during the sessions, and there were some non-consultation related questions regarding electricity rates following the connection of the remote communities identified in the Remote Community Connection Plan. At this point in time, it is not yet known how the distribution service would be structured and therefore it is not possible to determine the impact to rates in a detailed manner. Rates similar to other rural distribution customers in northwestern Ontario are believed to be expected. Other general comments included:

- the need for capacity building in communities to facilitate greater participation in consultation sessions
- some communities wish to focus on project-level consultation with proponents due to the more immediate potential impacts.

8.2 Municipal Engagement

Following the publication of the Draft North of Dryden IRRP, the OPA travelled across the northwest to meet with various municipal representatives from affected municipalities. The following summarizes these meetings:

Table 52: Municipal Engagement Summary

Meeting Date	Municipality
December 10, 2013	Pickle Lake
December 10, 2013	Greenstone
December 12, 2013	Red Lake
December 12, 2013	Sioux Lookout
December 13, 2013	Marathon
February 12, 2014	Dryden
February 13, 2014	Ignace

Following the municipal engagement meetings, several themes emerged as common feedback from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

Various municipal representatives provided input that any new transmission being contemplated in northwestern Ontario should be built to 230 kV standards in order to accommodate potentially high growth and encourage economic development. In general, the OPA agrees with this philosophy if there is sufficient justification to spend the incremental cost associated with a more expensive 230 kV option compared to a less expensive 115 kV option.

The OPA considered this feedback in updating the Draft North of Dryden IRRP that was released on August 16th, 2013. In the draft IRRP, the OPA indicated that it had no preference to the voltage for the recommended new line to Pickle Lake. In this version of the IRRP, the OPA was able to find sufficient justification for initially building and operating the recommended new line to Pickle Lake to 230 kV. The justification is based on the fact that the reference scenario forecast exceeds the capability of a 115 kV line in the longer term, and the provision of option flexibility for supplying the Ring of Fire as described in Section 7.2.

Cost responsibility was another common point of feedback. Generally the municipal representatives communicated that the infrastructure being contemplated in the North of Dryden IRRP is to enable economic development. Economic development was said to provide broader benefits than the local customers and costs should therefore be shared more broadly. Cost responsibility for new transmission and distribution infrastructure will be determined by the OEB during the appropriate regulatory process. For example for applicable transmission lines, cost responsibility would be determined during the leave to construct application.

Another common theme communicated by municipal representatives was the sense of urgency to develop the near term recommendations of a new line to Pickle Lake and the line upgrades from Dryden to Red Lake. The OPA agrees that the recommendation of building a new 230 kV single circuit line to Pickle Lake and upgrading the lines between Dryden and Red Lake are required as soon as possible, and will continue to support their development within the capacity of the OPA.

8.3 Other Engagement Activities

Prior to the publication of the Draft North of Dryden IRRP, the OPA engaged with remote communities, municipalities, stakeholder groups and industry to better understand the needs of the North of Dryden sub-region and communicate options that the OPA was considering for the North of Dryden IRRP. Presentations were made to the following groups and events:

- Ontario Mining Conference – June, 2013
- Common Voice Northwest – May, 2013
- Kenora District Municipal Association AGM – February, 2013
- Central Corridor Energy Group/Wataynikaneyap Power – various meetings 2011-2014
- Sagatay Transmission L.P. – various meetings 2012-2014

- Sioux Lookout Aboriginal Advisory Management Board - Trades Conference Fall 2012
- Aboriginal Energy Forum – December 2012
- Keewaytinook Okimakanak Chiefs Annual Meeting – December 2012
- Red Lake Mining Forum – October 2012
- NWOFNTPC - various meetings 2011-2012

With the release of draft IRRP in August 2013, the OPA hosted a webinar on November 21, 2013 to provide a high-level overview of the plan and to start the dialogue on further developing and refining the plan. An archive of the webinar was posted to the OPA website for stakeholders and communities who were not able to participate.

The OPA also established a dedicated email address – northofdryden@powerauthority.on.ca – to receive written feedback on the draft IRRP and for correspondence about the plan.

9 SUMMARY OF RECOMMENDATIONS

The existing North of Dryden sub-region has met its load meeting capability. In order to accommodate the economic connection of remote First Nation communities and to enable forecasted growth in the mining sector, it is prudent to develop and implement the following recommended solutions as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long term forecast scenarios.

The estimated combined cost of recommendations (1) and (2) during the planning period is about $124 million (net present value). Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

Based on the reference scenario forecast, the recommended solutions are expected to satisfy the forecasted demand requirements for the Pickle Lake and Red Lake subsystem until beyond the end of the planning period. The high scenario forecast indicates that additional investments for the Red Lake subsystem may be required by

2030. The transmission and generation options available have relatively short lead times compared to the 2030 need date, based on the high scenario forecast. As a result, no further action needs to be taken at this time.

The OPA has also shown that under all forecast scenarios assessed in this version of the North of Dryden IRRP, transmission supply options to supply the Ring of Fire subsystem are more economic than remote generation options. The OPA therefore recommends that common infrastructure corridor planning to the Ring of Fire should include the consideration of the potential need for a transmission line to ensure economic and regulatory efficiencies. The OPA will monitor developments in the Ring of Fire subsystem to ensure potential customers, stakeholders and Aboriginal groups are aware of these findings.

The OPA will continue to monitor developments in the North of Dryden sub-region, such as: progress on the recommendations in this version of the plan, demand growth, conservation activities, and progress on developments at the Ring of Fire.

As developments in the North of Dryden sub-region reach new milestones, a new planning cycle for the sub-region will be initiated. The next planning cycle will take place within the next 1-5 years, consistent with the TSC, DSC, and the OPA's license, depending on if and when currently uncertain developments take place.

When the long-term needs for the Red Lake and Ring of Fire subsystems become more certain, reinforcement projects can be triggered in the next planning cycle with appropriate lead times to ensure that the needs will be met.

Some projects may require funding by customers, in accordance with the TSC. In these cases the projects cannot proceed until customers have committed the required resources and funding for development work to be completed. Therefore, the timing of these facilities may be dependent on when customers can identify their needs and provide commitment to the project.

Additionally, conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the North of Dryden sub-region. The OPA has and will continue to actively work with existing and future customers in the North of Dryden sub-region to pursue conservation and DG. The OPA will continue to work with interested customers to understand the availability of potential resources including conservation and customer based DG in the North of Dryden sub-region.

The recommended solutions in the North of Dryden sub-region are consistent with the broader planning and development work that is underway to ensure an adequate supply is available in the Northwest as a whole.

10 APPENDICES

10.1 List of Remote First Nation Communities in 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

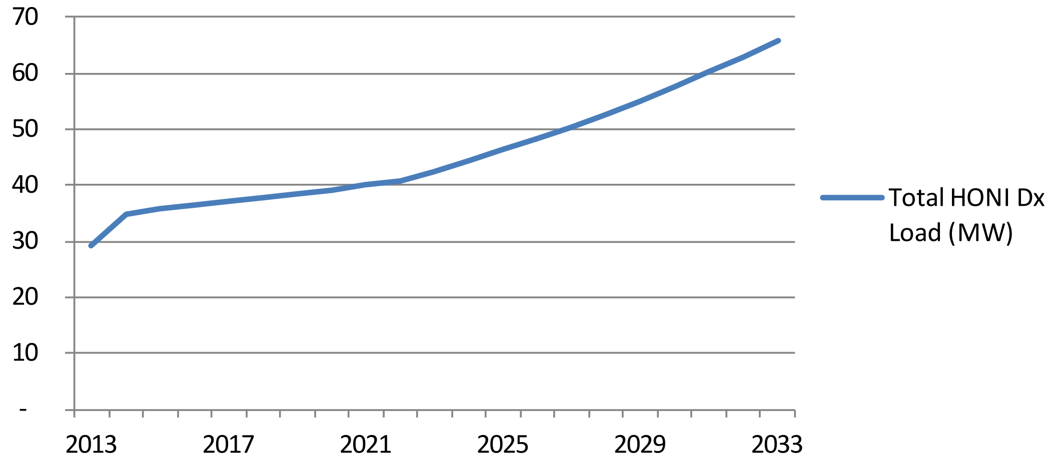
10.3.1 Hydro One Distribution - Reference Demand Forecast Methodology

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.

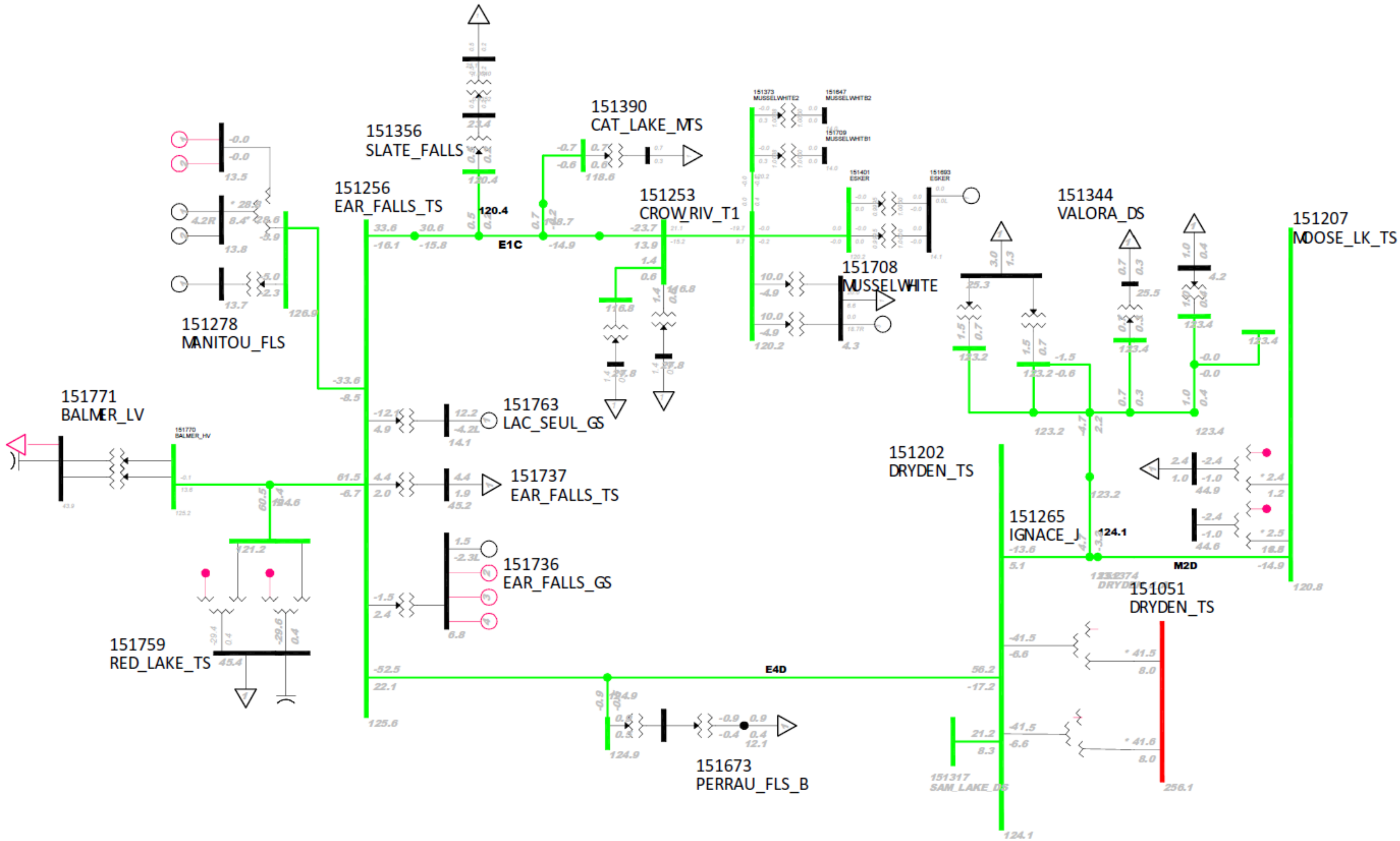
Local Area Assumptions

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



10.4.2 **Application of IESO Planning Criteria**

In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)[77]. In accordance with ORTAC, the transmission system supplying a local area shall have sufficient capability under peak demand conditions to withstand specific outages prescribed by ORTAC while keeping voltages, line and equipment loading within applicable limits. In determining the load meeting capability for each subsystem, ORTAC requires certain conditions to be respected. The supply options that are discussed for the North of Dryden sub-region assume that where new lines are built parallel to existing lines, some or all of the incremental load that is enabled for connection to the system, may be curtailed in the event of a forced outage of either line. This following is an excerpt from Section 7.1 of ORTAC which states:

> "The *transmission system* must be planned to satisfy *demand* levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The *transmission system* must exhibit acceptable performance, as described below, following the design criteria contingencies defined in sections 2.7.1 and 2.7.2. For the purposes of this section, an element is comprised of a single zone of protection.
>
> With all transmission *facilities* in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.
>
> With any one element out of service3, equipment loading must be within applicable long-term *emergency* ratings, voltages must be within applicable *emergency* ranges, and transfers must be within applicable normal condition stability limits. Planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150MW load interruption limit reflects past planning practices in Ontario."

Additionally, the following were assumed in this study to comply with ORTAC:

- Run of river hydroelectric generation should be assumed at a level that is available 98% of the time (ORTAC Section 2.6);

[77] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

- Load power factors is assumed to be 0.95 at the low voltage busbar to comply with the Market Rule of 0.9 at the defined meter point at the HV busbar (ORTAC Section 2.4);

- Voltage operating range of 113 kV to 132 kV for the 115 kV nominal system, and 220 kV to 250 kV for the 230 kV nominal system (ORTAC Section 2.4);

- Pre-contingency voltage maintained to the greater of (ORTAC Section 4.2):

    - At least 10% margin above the instability point

    - Minimum continuous voltage pre-contingency: 113 kV for 115 kV nominal system, and 220 kV for 230 kV nominal system

    - That which results in a post-contingency voltage of at least 108 kV for 115 kV nominal system, and 207 kV for 230 kV nominal system

- All line and equipment loading is within the continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service (ORTAC Section 4.7.2 and 7.1); and

- If the subsystem has transmission connected generation, the largest generator unit is assumed to be on outage pre-contingency and not available post-contingency.

The load meeting capability for each subsystem and each option are determined with the aid of PSS/E simulation, which represents a full model of the system, accounting for active and reactive power flows, losses, voltage drops, etc.

Table 57: Conditions for Determining Subsystem LMC

Local Area Supply	Conditions for LMC
Single Radial Line	Limit of the line during normal operating conditions.
Single Radial Line + Local Generation	Limit of the line during normal conditions; and Loss of the largest generating unit.

10.4.3 **Technical Study Procedures**

Once the needs for the subsystems were determined based on an assessment of the existing system and forecast net demand growth, the technical study identified how various options could meet the identified needs. From these needs, a range of generation and transmission options were developed that are capable of partially or fully meeting the identified needs. The capability of the options to serve the needs including the amount of voltage control required to meet the required LMC was determined.

Contingencies Considered in Option Assessment

A detailed list of the contingencies considered for the North of Dryden sub-region is outlined below in Table 58. All contingencies are limited to the loss of a single element (N-1) considering pre-contingency outage conditions consistent with ORTAC.

Table 58: Contingencies Considered in the Technical Study

Subsystem	Supply Option	Contingencies
Pickle Lake	CNG generation at Pickle Lake	Loss of single generating unit (10 MW) at Pickle Lake
		Loss of Manitou Falls GS
	New Line to Pickle Lake	N/A
Red Lake	NG generation at Red Lake	Loss of single generating unit (10 MW) at Red Lake
		Loss of Manitou Falls GS
	New Line to Ear Falls	Loss of New Line
		Loss of Manitou Falls GS
Ring of Fire	All	N/A

Determining Voltage Control Requirements

For each option in each subsystem, base cases were developed for both peak and light load conditions. Each subsystem was considered independently, and the effects of each option on the bulk system around Dryden TS and/or at Marathon TS were included.

Location and size of the voltage control devices for each test case was determined under the following load scenarios to satisfy the assumptions listed above.

1. Peak load conditions, all elements in service: This test determined the voltage control devices are required to ensure sufficient margin from the voltage collapse point. Voltage control devices were used to maintain the voltage within the ranges stated in the assumptions.

2. Zero load conditions: This test determined the amount of voltage control required to manage high voltages.

3. Light load conditions, all elements in service: This test was used to determine the required switching size and range of the voltage control devices.

4. Peak load conditions, largest local element out of service: In areas where contingencies were tested, voltage control device requirements before tap changing were determined.

Determining Load Meeting Capability of Options

This study uses the base cases that were developed for the peak load scenario in determining voltage control requirements, as stated above. For each subsystem, the LMC of the option following the installation of all facilities and voltage control devices that are required to meet the peak load forecast was determined for each option for each forecast scenario.

The LMCs for each option were determined using the following procedure:

1. The range of voltage control that was determined in the previous analysis was assumed to be available.

2. Peak load was assumed as a base. Thermal loading of transmission equipment was assessed.

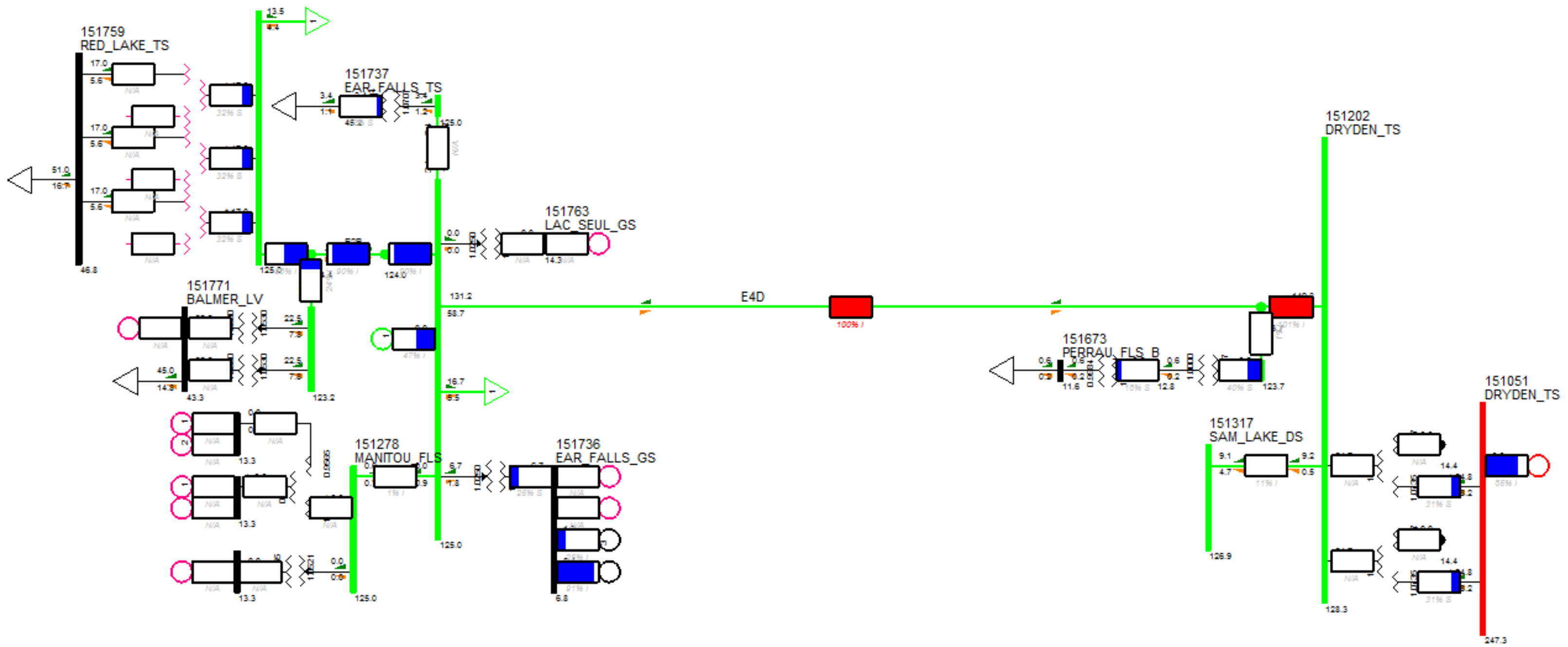
3. Where there was existing thermal capacity on transmission equipment, load was increased and new voltage control requirements were established, to determine the LMC. Load was increased at a central system bus within the subsystem (Pickle Lake area TS for the Pickle Lake subsystem, Ear Falls TS for the Red Lake subsystem, Mc Faulds TS for the Ring of Fire subsystem).

4. Following this, the system was tested allowing voltage control requirements to increase within reasonable limits.

More detailed studies for particular reinforcements may determine that voltage control devices can be located in alternative places closer to large loads, which may be found to optimize their value and reduce the overall cost. Specific connection requirements for individual customers, including requirements for additional voltage control devices will be identified by the IESO in future System Impact Assessments ("SIA").

A sample load flow case that was used to determine the LMC of the Red Lake subsystem after the upgrade of E4D and E2R is provided in Figure 17 below. In this case, the LMC for subsystem is 130 MW.

Figure 17: Sample of Methodology – Determining Post-Upgrade LMC of E4D and E2R Upgrade



10.5 Existing System Description and Load Meeting Capability

The North of Dryden electricity system is shown in Figure 18.

Figure 18: Existing North of Dryden Transmission System

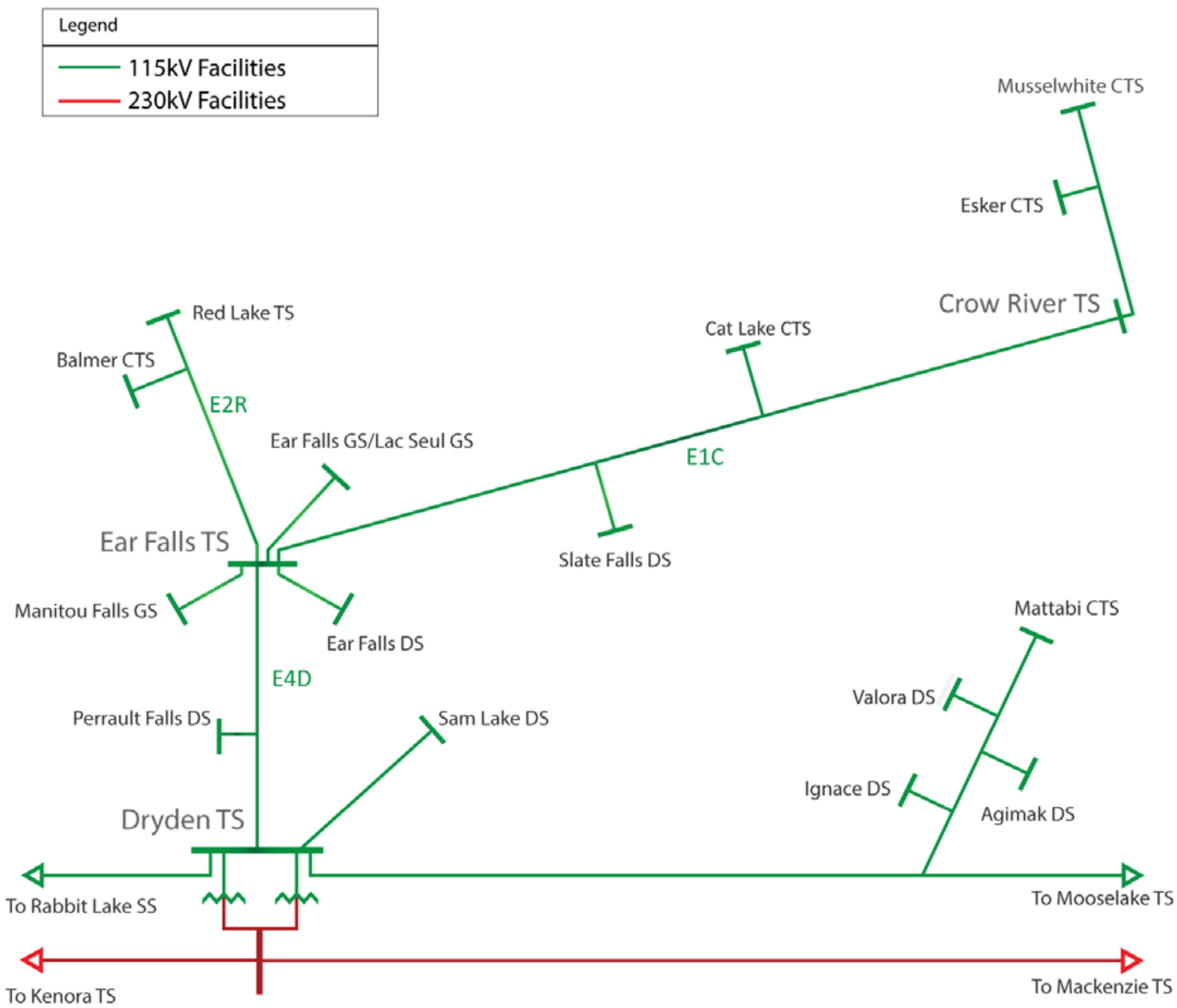
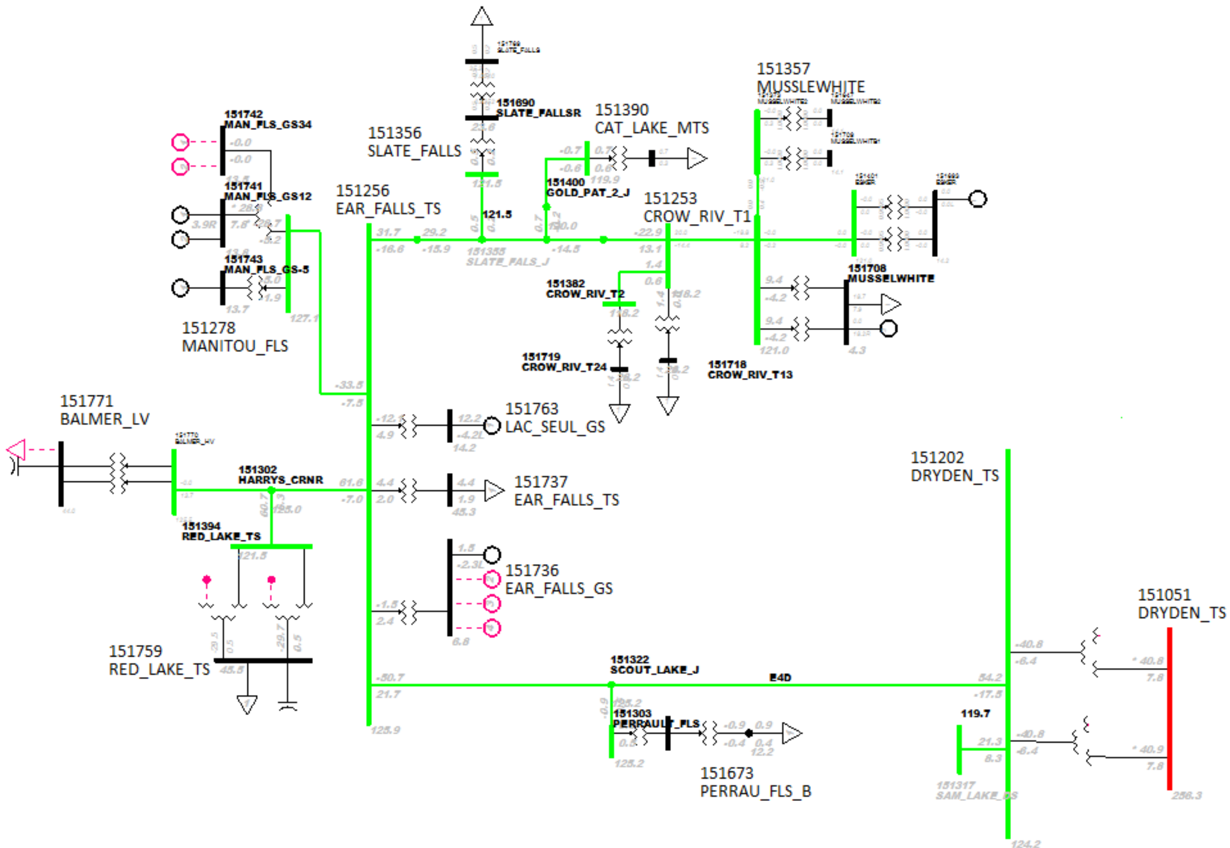


Figure 19: Existing North of Dryden Transmission System Load Flow Plot



Pickle Lake Subsystem

The Pickle Lake subsystem includes all load currently and planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as Musselwhite mine. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are planned to connect to Pickle Lake via a transmission line to Crow River DS.

Currently, the Pickle Lake subsystem has an LMC of 24 MW. Due to losses on the line E1C, supply of close to 35 MW is required from Ear Falls TS to serve this load along the line and at Pickle Lake. The LMC for the Pickle Lake subsystem is determined by the load that can be met during normal operating conditions.

Red Lake Subsystem

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities that lie north of Red Lake that are planned to connect to Red Lake TS. There is 102.2 MW of hydroelectric generation at Ear Falls/Lac Seul GS and at Manitou Falls GS.

Currently, the E4D and Ear Falls area generation is capable of supplying 85 MW from Ear Falls TS, which includes 61 MW in the Red Lake subsystem and 24 MW in the Pickle Lake subsystem.

Ring of Fire Subsystem

The Ring of Fire subsystem includes five remote communities that are planned for connection to the provincial transmission system as well as potential future industrial customers at the Ring of Fire. This subsystem may be connected to the provincial transmission system either at Pickle Lake, Marathon TS, or east of Nipigon.

The Ring of Fire subsystem is not currently supplied from the IESO-controlled grid and thus has a load meeting capability of 0 MW. However the 5 remote communities are currently served by local diesel generation in their communities.

10.6 **Analysis of Recommended Options**

As indicated in Section 0, the recommended options for the North of Dryden sub-region are:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

   For the list of assumptions and procedure pertaining to the assessment of generation options, refer to Section 10.7. For a list of assumptions and procedure pertaining in the assessment of transmission options, refer to Section 10.8

Recommendation 1: New single circuit 230 kV line to Pickle Lake and supporting facilities

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

Table 59: Summary of Load Meeting Capability of Recommendation

Recommendation	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
230 kV line to Pickle Lake	136 MW	160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Table 60 outlines the cash flows used for the net present value economic analysis. Figure 20 and Figure 21 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

Table 60: Summary of Cashflow for New Line to Pickle Lake at 230 kV[78]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				28.4																
O&M				1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Annual Cost	0.0	0.0	0.0	168.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Annual Amortized Cost				9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Cumulative PV	0.0	0.0	0.0	8.4	16.4	24.1	31.5	38.7	45.5	52.1	58.5	64.6	70.5	76.1	81.5	86.8	91.8	96.6	101.2	105.7

[78] Includes compensation required to supply Reference load forecast scenario (78 MW in 2033).

Figure 20: New 230 kV line to Pickle Lake Diagram

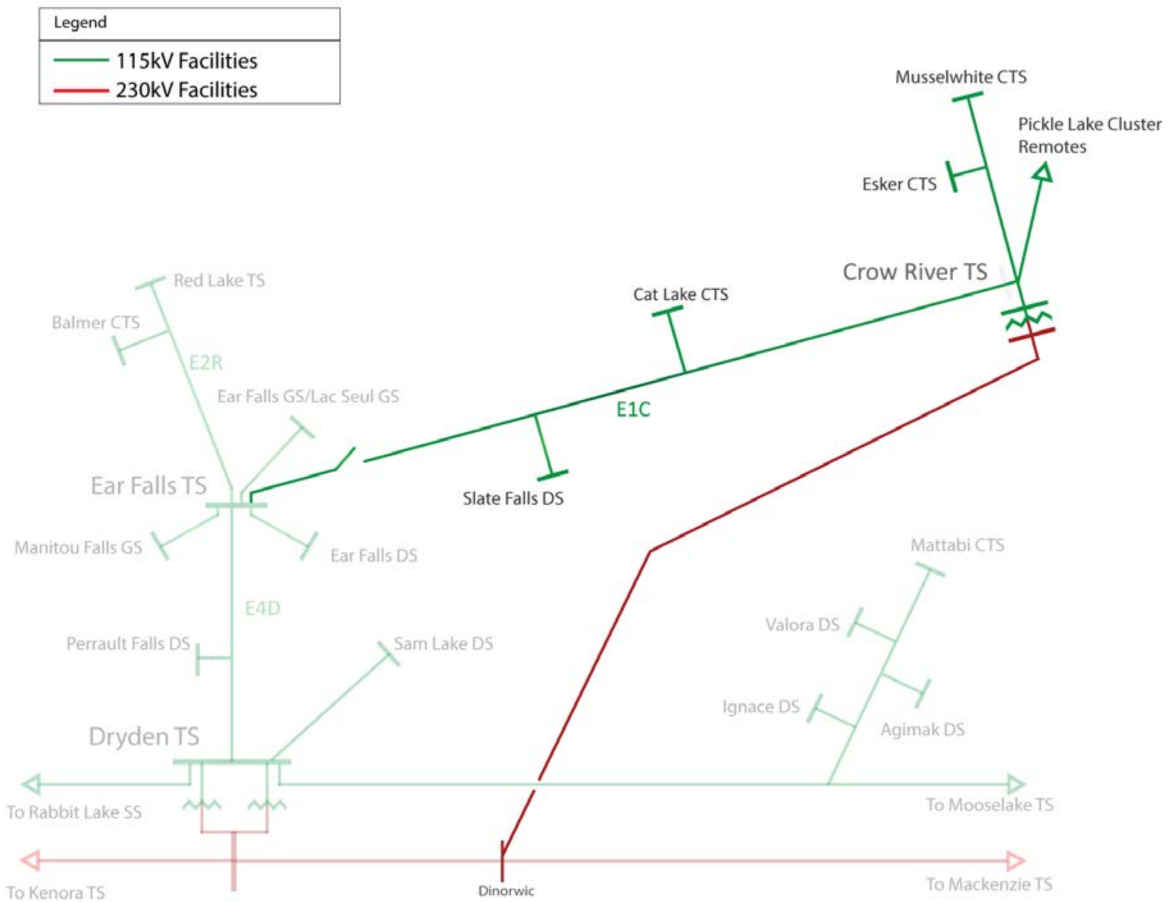
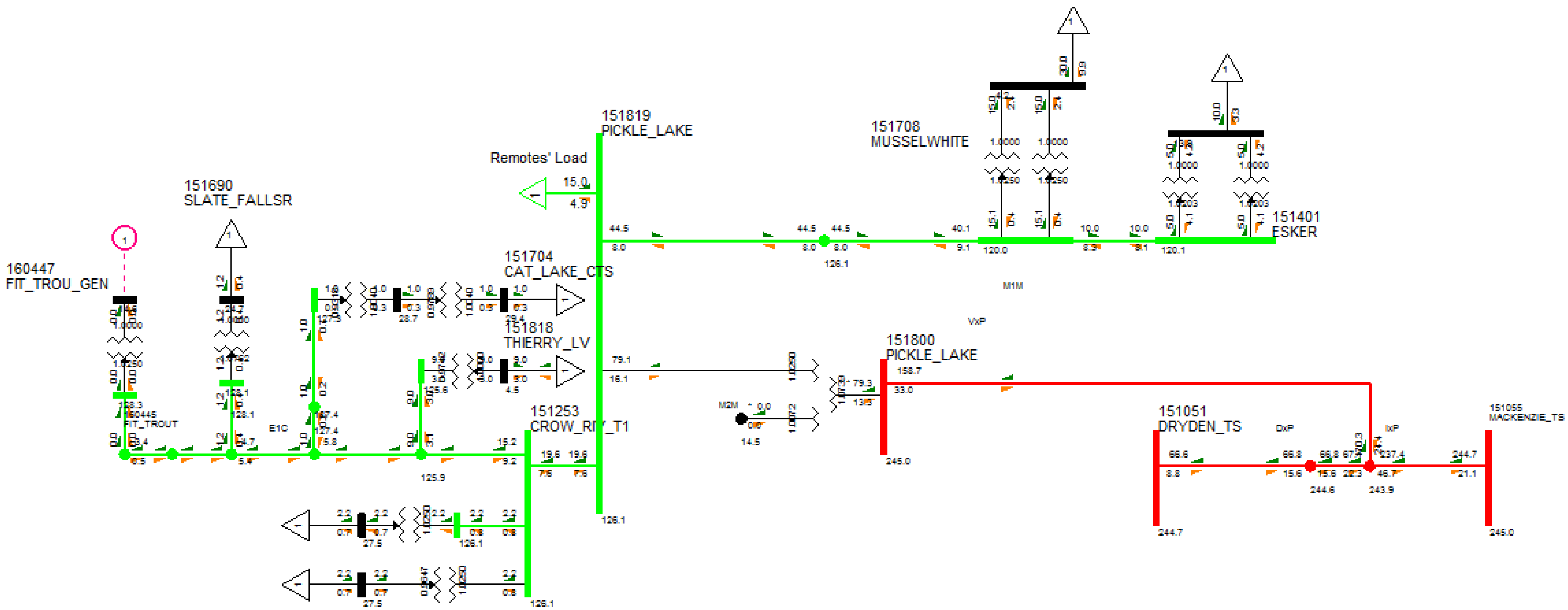


Figure 21: 230 kV Line Option Pickle Lake Subsystem Configuration



Recommendation 2: Upgrade circuits E4D and E2R and supporting facilities

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

Table 61: Summary of Load Meeting Capability of Recommendation

<table>
<tr><th>Recommendation</th><th>Incremental Capacity</th><th>Load Meeting Capability</th><th>Low Forecast Demand</th><th>Reference Forecast Demand</th><th>High Forecast Demand</th></tr>
<tr><td rowspan="2">Upgrade E4D and E2R
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>34 MW</td><td>95 MW</td><td rowspan="2">100 MW</td><td rowspan="2">109 MW</td><td rowspan="2">136 MW</td></tr>
<tr><td>35 MW</td><td>130 MW</td></tr>
</table>

Table 62 outlines the cash flows used for the net present value economic analysis. Figure 22 and Figure 23 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

Table 62: Summary of Cashflows for Upgrade to E4D and E2R

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line Cost	0.0	5.0																		
Station Cost	0.0	10.5																		
O&M	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Annual Cost	0.0	15.7	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Annual Amortized Cost	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Cumulative PV	0.0	0.8	1.6	2.4	3.2	3.9	4.6	5.2	5.9	6.5	7.1	7.7	8.2	8.7	9.2	9.7	10.2	10.6	11.1	11.5

Figure 22: E4D and E2R Upgrade Diagram

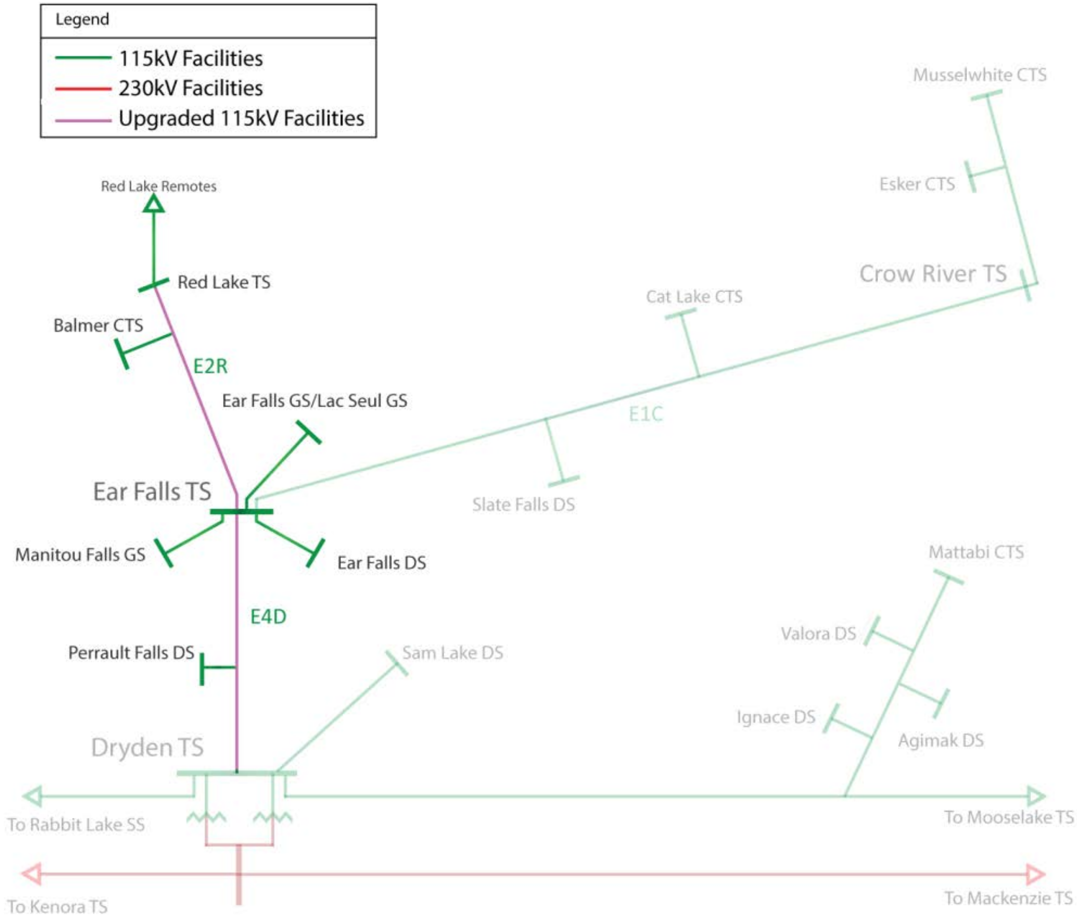
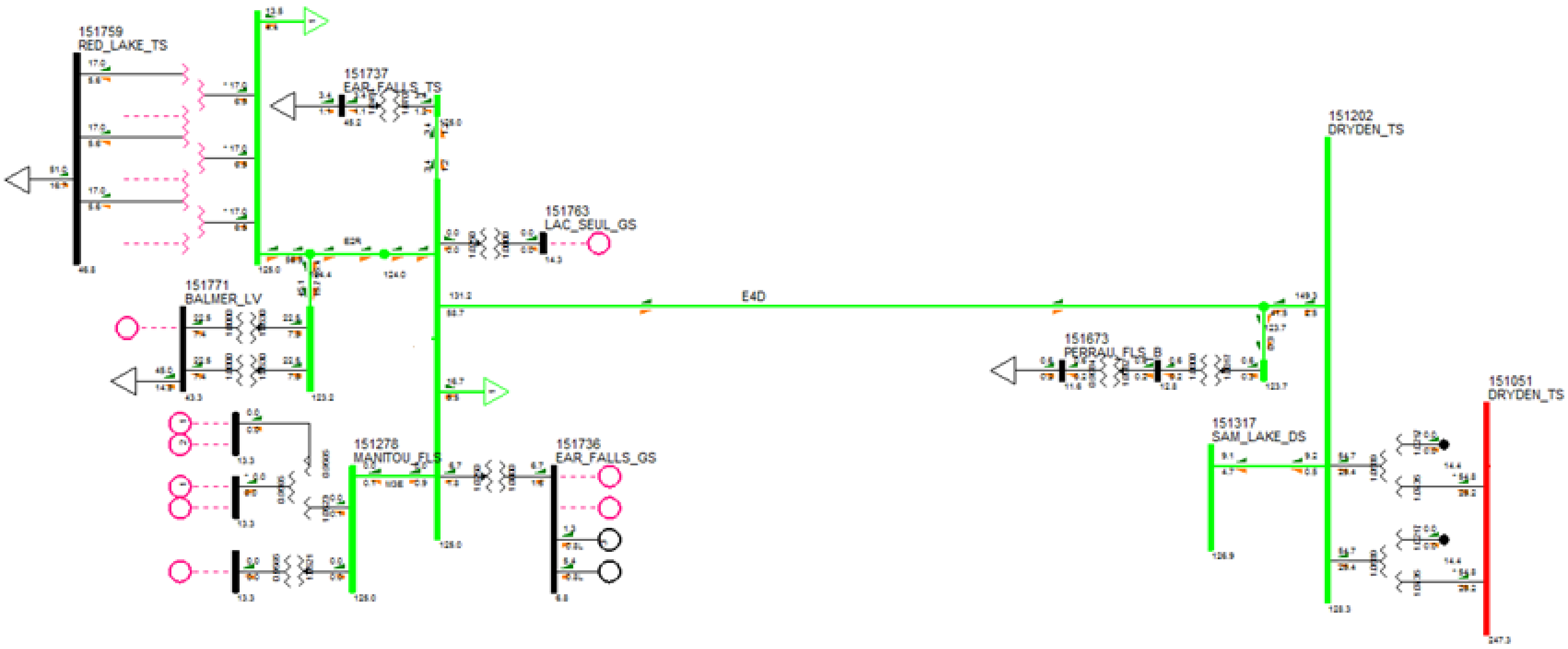


Figure 23: E4D and E2R Upgrade Red Lake Subsystem Configuration



Recommendation 3: Manitou Falls condense operation during drought conditions

In order to accommodate future growth in the Red Lake subsystem, new voltage control devices would need to be installed in the Ear Falls and Red Lake areas. New voltage control devices would be required in order to release the thermal capability provided to the Red Lake subsystem from the system upgrades being recommended.

OPG has informed the OPA that Manitou Falls units G1, G2, and G3 could be made to condense with minor maintenance work. Units G1, G2, and G3 would have a capability of approximately +/-14 MVar each, for a total of +/- 42 MVar. The OPA anticipates that the NPV cost associated with enabling and operating the condense features over the planning period is likely to be significantly less than the NPV cost of installing new voltage control devices.

10.7 Generation Options

For each of the three subsystems, at least one generation option was studied in detail. However, due to the different nature of each system, and thus the differing needs, each system was approached with a unique methodology to ensure that the generation option/s studied reflect the need of the subsystem.

The assumptions and methodologies used for developing the generation options are described below.

10.7.1 Pickle Lake Subsystem

Assumptions

The following assumptions were used to estimate the cost of CNG electricity generation in the Pickle Lake subsystem:

- Pickle Lake subsystem will remain connected to Ear Falls TS and 24 MW of load in the Pickle Lake subsystem will be served from Ear Falls TS

- Forecasted demand greater than 24 MW in the Pickle Lake subsystem (including remote communities in the Ring of Fire subsystem connecting at Pickle Lake) would be served by CNG fueled generation at Pickle Lake
- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed
- Generation would be fueled mainly by CNG, which would be compressed and transported from TCPL pipeline in the Ignace area via Highway 599
- Decanting stations would be required to decompress the natural gas for use
- CNG fuel delivery would be on a just in time basis due to challenges with large scale on-site CNG storage
- If CNG is unavailable generators will run on diesel, cost of supplying diesel and storage has not been included
- A sufficient number of trailers would be required to transport CNG as well as provide for some limited on-site storage to ensure a stable flow of fuel
- A Special Protection System triggered by the loss of more than one generator in the new facility, may be required to automatically shed load sufficient to maintain operation of E1C within appropriate limits
- Discrete generator unit sizes of 9.5 MW

Study Procedure

To determine the feasibility and estimate the cost of implementing a CNG generation facility in the Pickle Lake subsystem, the following procedure was undertaken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity at Pickle Lake that would be required to meet the peak forecast demand of the subsystem.
2. Using established transmission limits, hydroelectric generation profiles and load profiles for the subsystem, the capacity and energy that would need to be served by new CNG generation resources was estimated.
3. Using energy requirements estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;

4. Using generator capacity, number of trailers and annual energy requirements, capital, operations and maintenance, and fuel costs of the system were calculated.
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

Planning Level Assessment

A summary of the technical capability of the generation options that were considered for the Pickle Lake subsystem is summarized below.

Table 63: Summary of Capacity for Gas Generation at Pickle Lake

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
CNG Generation at Pickle Lake (38 MW)	19 MW	43 MW	41 MW	78 MW	90 MW
CNG Generation at Pickle Lake (47.5 MW)	23.5 MW	47.5 MW			
CNG Generation at Pickle Lake (76 MW)	57 MW	81 MW			
CNG Generation at Pickle Lake (85.5 MW)	66.5 MW	90.5 MW			

*Requires continued supply of 24 MW of load via E1C from Ear Falls

**Includes demand for Ring of Fire remote communities (7 MW)

The cost of supplying the growth needs of the Pickle Lake subsystem with CNG fueled generation are shown in Table 64 through Table 69. Figure 24 shows operation of the Pickle Lake subsystem with this option in the peak load case. Voltage profiles throughout the subsystem remain healthy in the general range of 118 kV to 125 kV. The installation of generation at Pickle Lake also provides some voltage control to the Pickle Lake subsystem.

Table 64: Summary of Cost for 38 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	56.8	0.0	0.0	0.0	4.7	0.0	0.0	0.0	4.0	0.0	16.0	0.0	3.0	0.0	0.0	0.0	2.9
O&M and Fuel	0.0	0.0	0.0	10.5	10.2	9.8	9.4	9.1	8.7	8.4	8.1	7.7	7.4	5.3	5.3	5.3	5.3	5.3	5.3	5.4
System Gen Credit	0.0	0.0	0.0	0.0	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Total Annual Gx Cost	0.0	0.0	0.0	67.2	8.7	8.3	7.9	12.2	7.2	6.9	6.6	10.2	6.0	19.8	3.8	6.8	3.8	3.8	3.8	6.8
Annual Amortized cost	0.0	0.0	0.0	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	10.3	20.3	29.8	39.0	47.9	56.4	64.5	72.4	80.0	87.2	94.2	100.9	107.4	113.6	119.6	125.3	130.8

Table 65: Summary of Cost for 47.5 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	66.4	0.0	0.0	0.0	7.2	0.0	0.0	0.0	8.0	0.0	27.7	0.0	5.6	0.0	0.0	0.0	6.4
O&M and Fuel	0.0	0.0	0.0	12.7	13.0	13.3	13.6	13.9	14.2	14.6	14.9	15.3	15.7	9.7	10.1	10.4	10.8	11.2	11.7	12.2
System Gen Credit	0.0	0.0	0.0	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1
Total Annual Gx Cost	0.0	0.0	0.0	79.1	5.9	6.1	6.4	14.0	7.1	7.4	7.8	16.2	8.5	30.2	2.9	8.8	3.7	4.1	4.6	11.5
Annual Amortized cost	0.0	0.0	0.0	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	12.1	23.7	34.9	45.6	56.0	65.9	75.5	84.6	93.5	102.0	110.1	118.0	125.5	132.8	139.8	146.5	152.9

Table 66: Summary of Cost for 76 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	124.2	0.0	0.0	0.0	9.6	0.0	0.0	0.0	12.8	0.0	52.4	0.0	15.2	0.0	0.0	0.0	18.4
O&M and Fuel	0.0	0.0	0.0	16.0	16.3	17.8	18.4	19.9	21.2	22.6	24.0	25.6	27.0	25.9	27.3	28.9	30.4	31.9	33.4	35.1
System Gen Credit	0.0	0.0	0.0	0.0	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1
Total Annual Gx Cost	0.0	0.0	0.0	140.2	2.2	3.7	4.3	15.3	7.1	8.5	9.9	24.2	12.9	64.1	13.2	30.0	16.3	17.8	19.3	39.4
Annual Amortized cost	0.0	0.0	0.0	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7
Cumulative PV of Amortized cost	0.0	0.0	0.0	22.8	44.8	65.9	86.1	105.7	124.4	142.4	159.8	176.5	192.5	207.9	222.7	237.0	250.7	263.9	276.5	288.7

Table 67: Summary of Cost for Compensation Associated with up to 76 MW of Gas Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost				8.1																
O&M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	8.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost				0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cumulative PV	0.0	0.0	0.0	0.4	0.8	1.2	1.5	1.9	2.2	2.5	2.8	3.1	3.4	3.7	4.0	4.2	4.5	4.7	4.9	5.1

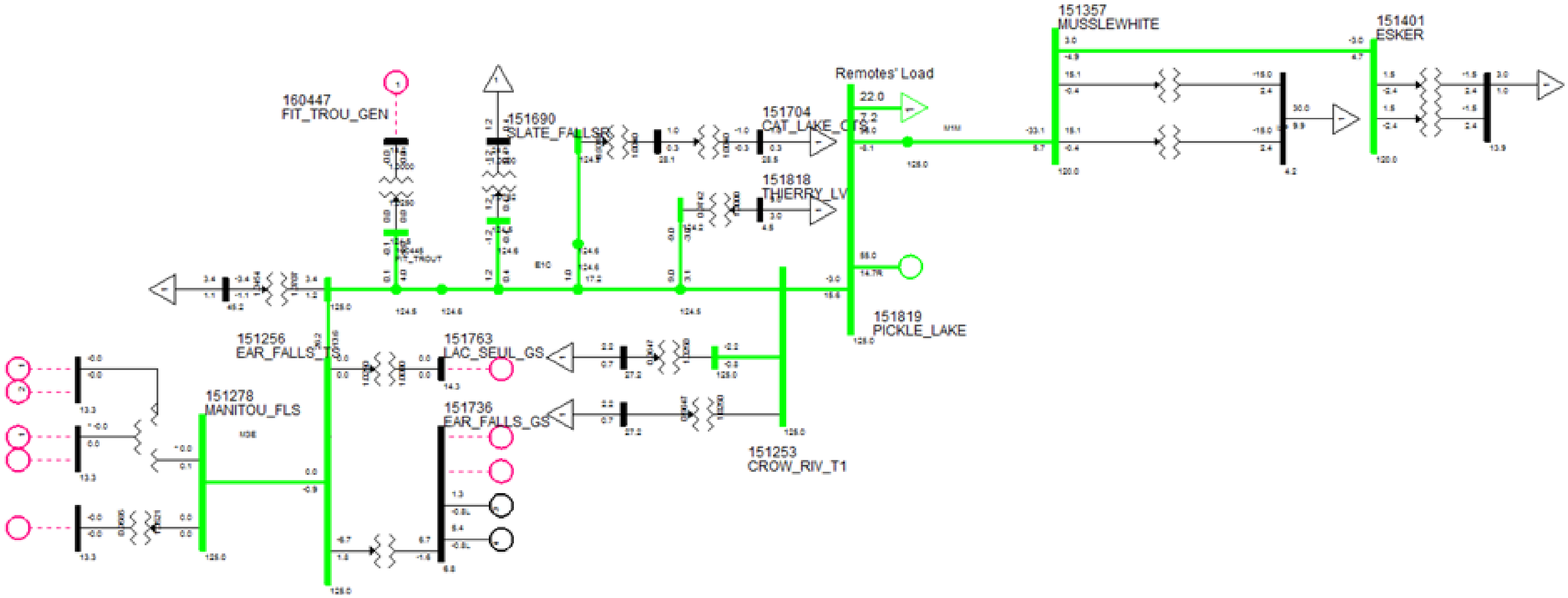
Table 68: Summary of Cost for 85.5 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	125.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	15.2	0.0	52.4	0.0	18.4	0.0	0.0	0.0	22.4
O&M and Fuel	0.0	0.0	0.0	17.1	17.3	22.0	22.5	24.1	25.4	26.8	28.2	29.8	31.2	32.6	34.1	35.7	37.2	38.7	40.2	41.9
System Gen Credit	0.0	0.0	0.0	0.0	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4
Total Annual Gx Cost	0.0	0.0	0.0	142.1	0.0	4.6	5.1	18.7	8.0	9.4	10.8	27.6	13.8	67.6	16.7	36.7	19.8	21.3	22.8	46.9
Annual Amortized cost	0.0	0.0	0.0	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3
Cumulative PV of Amortized cost	0.0	0.0	0.0	24.3	47.7	70.2	91.8	112.6	132.5	151.8	170.2	188.0	205.1	221.5	237.3	252.5	267.1	281.1	294.6	307.6

Table 69: Summary of Cost for Compensation Associated with up to 85.5 MW of Gas Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost				14.7																
O&M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	14.8	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost				0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.7	1.4	2.1	2.8	3.4	4.0	4.6	5.2	5.7	6.2	6.7	7.2	7.7	8.1	8.5	8.9	9.3

Figure 24: Generation Option Pickle Lake Subsystem Configuration



10.7.2 **Red Lake Subsystem Generation Options**

Assumptions

The following assumptions were used to estimate the cost of natural gas electricity generation in the Red Lake subsystem:

- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area for 30 MW generation (near-term) option;
- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area and a new gas pipeline to future customer(s) for the 60 MW (long-term) option;
- Pipelines are assumed to be available and associated costs are not included in this analysis (except gas management charges). New pipeline capacity required for the second 30 MW of gas generation at Ear Falls is assumed to be linked to a future potential load customer, therefore if the incremental gas capacity is not developed neither will the load be present in the subsystem; and
- Discrete generator unit sizes of 9.5 MW.

Study Procedure

To estimate the cost of implementing natural gas generation in the Red Lake subsystem, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity required to meet the need of the Red Lake subsystem;
2. Using established transmission limits, hydroelectric generation profiles and the identified need for the subsystem, determine the capacity and energy that new generation resources would need to served;
3. Using established unit costs, capital, operations and maintenance, and fuel costs of the new generation resources were calculated;
4. Using capacity size, gas management charges for a peaking facility in the area were estimated; and
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2014-2033) was calculated.

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.

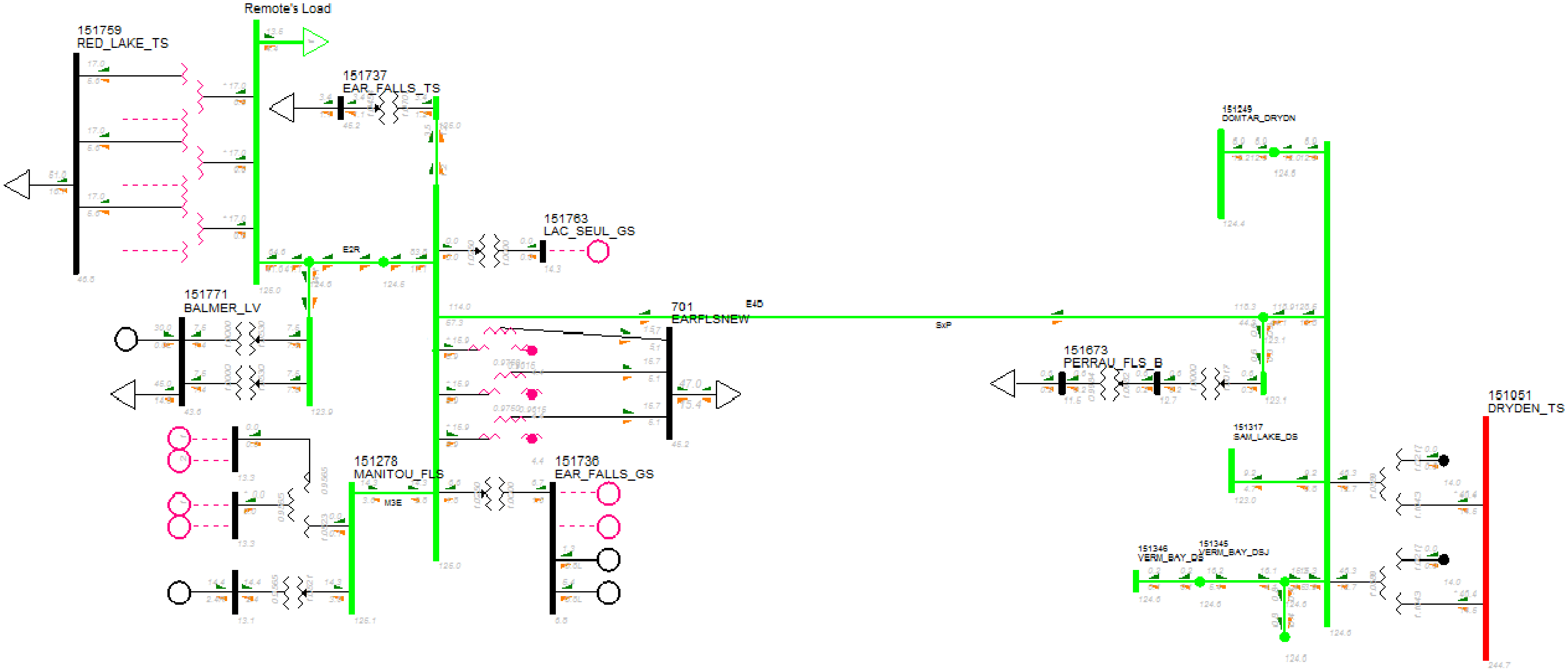
Table 71: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

	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



Given the existing opportunity for 30 MW of gas generation at Red Lake, a second gas generator at Ear Falls could be sized to serve the remaining capacity needs of the Red Lake subsystem. With a total of 60 MW of gas generation in the Red Lake subsystem, the LMC of the subsystem would increase by 60 MW to 190 MW (assuming all Pickle Lake subsystem load on E1C is transferred to the new line to Pickle Lake). Table 73 summarizes the capacity provided by a single 30 MW facility at Red Lake as well as two facilities in the subsystem.

Table 73: Summary of Incremental Capacity and LMC

Option	Incremental Capacity	Load Meeting Capability*	Low Forecast Long-term Demand	Reference Forecast Long-term Demand	High Forecast Long-term Demand
NG Generation at Ear Falls (30 MW)	30 MW	160 MW	100 MW	109 MW	136 MW
NG Generation at Ear Falls (60 MW)	60 MW	190 MW			

*Includes the capability of E4D and E2R after upgrading

Figure 25 and Figure 26, show the state of the Red Lake subsystem with each of these options implemented, while Table 74 to Table 77, provide a detailed summary of the costs for each option. The generators at Red Lake and/or Ear Falls help to maintain the voltages at those buses to a healthy range of 120 kV to 125 kV.

Table 74: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost																	80.9			
Fixed O&M																	1.8	1.8	1.8	1.8
Variable O&M																	0.0	0.0	0.0	0.0
Fuel Cost																	0.0	0.0	0.0	0.0
Avoided System Gen Cost																	-2.7	-2.7	-2.7	-2.7
Total Annual Gx Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.1	-0.9	-0.9	-0.9
Annual Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9	4.9	4.9	4.9
Cumulative PV of Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	2.3	3.4	4.4

Table 75: Summary of Cost for Compensation Associated with 30 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost																	14.1			
O&M																	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.2	0.1	0.1	0.1
Annual Amortized Cost																	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.8	1.2	1.6

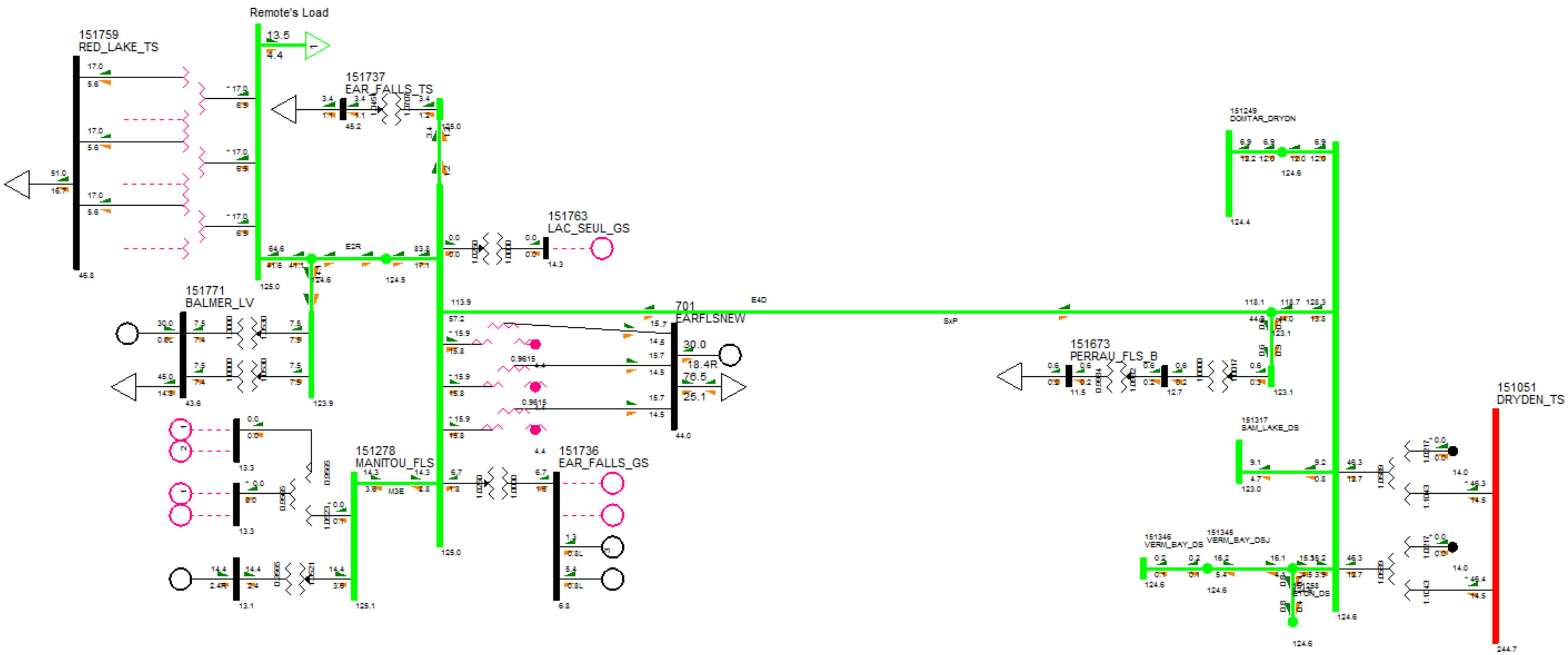
Table 76: Summary of Cost for 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost																	145.7			
Fixed O&M																	3.0	3.0	3.0	3.0
Variable O&M																	0.0	0.0	0.0	0.0
Fuel Cost																	0.0	0.0	0.0	0.0
Avoided System Gen Cost																	-4.9	-4.9	-4.9	-4.9
Total Annual Gx Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	143.8	-1.9	-1.9	-1.9
Annual Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.4	8.4	8.4	8.4
Cumulative PV of Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	3.7	5.5	7.2

Table 77: Summary of Cost for Compensation Associated with 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost																	6.9			
O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.1	0.1	0.1
Annual Amortized Cost																	0.4	0.4	0.4	0.4
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.8

Figure 26: 60 MW Generation Option Red Lake Subsystem Configuration



10.7.3 Ring of Fire Subsystem Options

Assumptions

The following assumptions were made to determine the infrastructure required to implement diesel and CNG fueled generation at the mine-sites and its costs. Based on the infrastructure requirements, costs for capital, operating and maintenance and capital sustainment were estimated to determine the total cost of generating electricity at Ring of Fire mine-sites. For both fuel options, generators are assumed to not be connected to the Ontario electricity system.

Assumptions for CNG Fueled Mine-site Generation:

- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed;
- CNG would be compressed at a new compressor station in the Nakina area and transported on specialized high pressure transport trailers via the proposed road to the mine-sites;
- Decanting stations near the generators would be required to decompress the natural gas for use;
- CNG fuel delivery would be on a just in time basis due to challenges and additional cost of large scale on-site CNG storage;
- If CNG is unavailable generators will run on diesel;
- A sufficient number of trailers would be required to both transport fuel as well as provide for some limited on-site storage to ensure a stable flow of fuel; and
- Discrete generator unit sizes of 9.5 MW.

Assumptions for Diesel Fueled Mine-site Generation:

- Generators will be diesel fueled reciprocating engines;

- Diesel would be supplied from the Thunder Bay area and transported to the mine-sites via the proposed all-weather road, stored on site and used for in-mine equipment as well as for electricity generation;
- On-site diesel storage is available due to the variety of uses for diesel at the mine-sites, therefore timing and logistic challenges with fuel transport and delivery will not be as significant as for CNG; and
- Discrete generator unit sizes of 9.5 MW.

Study Procedure

To estimate the cost of implementing a CNG or diesel electricity generation facility at the Ring of Fire mine-sites, the following procedure was undertaken:

1. Determine forecast peak load for the Ring of Fire mines based on the demand forecast;
2. Determine the required amount of generation capacity based on peak load;
3. Calculate the energy requirements (total kWh per year) by applying a estimated load factor to the peak load;
4. Calculate fuel required daily based on energy requirements;
5. Estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;
6. (CNG option only) Determine number of compressor and decanting stations based on amount of fuel required per day; and
7. Use the calculated values (generator capacity, number of trucks, annual fuel requirements, and decanting/compressing stations) to calculate initial capital costs, refurbishment costs, operation and maintenance costs, and fuel costs of the system.
8. These capital, operations and maintenance costs, were amortized over the project life and the present value over the planning period (2013-2033) was calculated.

Planning Level Assessment

The generation options considered for supplying the Ring of Fire subsystem would only supply the mining load. The five remote communities in the Ring of Fire subsystem have been determined to be economic to connect as per the findings of the Remote Community Connection Plan. Backup generation capacity is considered to use consistent reliability criteria specified under ORTAC. Table 78 outlines the generation solution options considered for the Ring of Fire subsystem mining demand.

Table 78: Summary of Incremental Capacity and LMC

Option	Incremental Capacity	Load Meeting Capability for Mining	Low Forecast Long-term Mining Demand	Reference Forecast Long-term Mining Demand	High Forecast Long-term Mining Demand
38 MW of CNG	22 MW	22 MW	0 MW	22 MW	66 MW
38 MW of Diesel	22 MW	22 MW			
57 MW of CNG	44 MW	44 MW			
57 MW of Diesel	44 MW	44 MW			
85.5 MW of CNG	71 MW	71 MW			
85.5 MW of Diesel	71 MW	71 MW			

Table 79 through Table 83 below summarize the cost profiles for each option.

Table 79: Summary of Cost for 38 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	39.8	0.0	0.0	0.0	1.8	0.0	0.0	0.0	1.8	0.0	24.7	0.0	1.8	0.0	0.0	0.0	1.8
O&M and Fuel	0.0	0.0	0.0	31.6	32.1	32.6	33.1	33.7	34.2	34.8	35.4	36.0	44.5	45.2	45.9	46.7	47.4	48.1	48.8	49.6
System Gen Credit	0.0	0.0	0.0	0.0	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Total Annual Gx Cost	0.0	0.0	0.0	71.4	23.8	24.3	24.8	27.1	25.9	26.5	27.0	29.5	36.1	61.5	37.6	40.1	39.1	39.8	40.4	43.1
Annual Amortized cost	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Cumulative PV of Amortized cost	0.0	0.0	0.0	31.1	61.0	89.7	117.3	143.9	169.5	194.0	217.7	240.4	262.2	283.2	303.4	322.8	341.5	359.4	376.7	393.3

Table 80: Summary of Cost for 57 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	58.8	0.0	0.0	0.0	3.0	0.0	0.0	0.0	3.0	0.0	37.1	0.0	3.6	0.0	0.0	0.0	3.6
O&M and Fuel	0.0	0.0	0.0	32.2	32.7	33.2	72.7	74.0	75.2	76.5	77.8	79.2	88.4	89.8	91.2	92.7	94.3	95.6	97.0	98.6
System Gen Credit	0.0	0.0	0.0	0.0	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Total Annual Gx Cost	0.0	0.0	0.0	91.0	15.9	16.4	55.9	60.2	58.4	59.7	61.0	65.4	71.6	110.0	74.4	79.5	77.5	78.8	80.2	85.4
Annual Amortized cost	0.0	0.0	0.0	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7
Cumulative PV of Amortized cost	0.0	0.0	0.0	53.1	104.1	153.2	200.4	245.8	289.4	331.4	371.7	410.5	447.8	483.7	518.1	551.3	583.2	613.8	643.3	671.7

Table 81: Summary of Cost for 85.5 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	87.3	0.0	0.0	0.0	4.8	0.0	0.0	0.0	4.8	0.0	55.6	0.0	5.4	0.0	0.0	0.0	5.4
O&M and Fuel	0.0	0.0	0.0	33.1	33.5	34.1	112.6	114.6	116.5	118.5	120.5	122.7	132.6	134.7	136.8	139.1	141.5	143.5	145.5	148.0
System Gen Credit	0.0	0.0	0.0	0.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0
Total Annual Gx Cost	0.0	0.0	0.0	120.4	6.5	7.1	85.6	92.4	89.5	91.5	93.5	100.5	105.6	163.3	109.8	117.5	114.5	116.5	118.5	126.4
Annual Amortized cost	0.0	0.0	0.0	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1
Cumulative PV of Amortized cost	0.0	0.0	0.0	74.8	146.7	215.9	282.3	346.3	407.7	466.9	523.7	578.3	630.9	681.4	730.0	776.7	821.6	864.8	906.3	946.3

Table 82: Summary of Cost for 38 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	65.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	8.0	0.0	24.7	0.0	10.4	0.0	0.0	0.0	10.4
O&M and Fuel	0.0	0.0	0.0	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	18.7	18.7	18.7	18.9	18.9	18.9	18.9	18.9
System Gen Credit	0.0	0.0	0.0	0.0	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Total Annual Gx Cost	0.0	0.0	0.0	80.7	7.4	7.4	7.4	15.4	7.4	7.4	7.4	15.4	10.4	35.1	10.4	20.9	10.5	10.5	10.5	20.9
Annual Amortized cost	0.0	0.0	0.0	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	16.5	32.4	47.7	62.4	76.6	90.2	103.2	115.8	127.9	139.5	150.7	161.4	171.7	181.7	191.2	200.4	209.2

Table 83: Summary of Cost for 57 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	93.5	0.0	0.0	0.0	18.4	0.0	0.0	0.0	18.4	0.0	37.1	0.0	20.0	0.0	0.0	0.0	20.0
O&M and Fuel	0.0	0.0	0.0	16.6	16.6	16.6	33.2	33.7	33.7	33.7	33.7	33.7	36.7	36.7	36.7	36.8	36.8	36.8	36.8	36.8
System Gen Credit	0.0	0.0	0.0	0.0	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Total Annual Gx Cost	0.0	0.0	0.0	110.1	-0.2	-0.2	16.4	35.3	16.9	16.9	16.9	35.3	19.9	57.0	19.9	40.0	20.0	20.0	20.0	40.0
Annual Amortized cost	0.0	0.0	0.0	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
Cumulative PV of Amortized cost	0.0	0.0	0.0	24.8	48.6	71.6	93.6	114.8	135.2	154.8	173.6	191.7	209.1	225.9	242.0	257.5	272.4	286.7	300.4	313.7

Table 84: Summary of Cost for 85.5 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	136.3	0.0	0.0	0.0	28.0	0.0	0.0	0.0	28.0	0.0	55.6	0.0	29.6	0.0	0.0	0.0	29.6
O&M and Fuel	0.0	0.0	0.0	17.9	17.9	17.9	51.1	52.1	52.1	52.1	52.1	52.1	55.1	55.1	55.1	55.2	55.2	55.2	55.2	55.2
System Gen Credit	0.0	0.0	0.0	0.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0
Total Annual Gx Cost	0.0	0.0	0.0	154.1	-9.1	-9.1	24.1	53.1	25.1	25.1	25.1	53.1	28.1	83.7	28.1	57.8	28.2	28.2	28.2	57.8
Annual Amortized cost	0.0	0.0	0.0	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1
Cumulative PV of Amortized cost	0.0	0.0	0.0	33.0	64.7	95.2	124.6	152.8	179.9	206.0	231.1	255.2	278.3	300.6	322.1	342.7	362.5	381.6	399.9	417.5

10.8 Transmission Options

Assumptions

In determining the cost of transmission options, the following were assumed:

- Unit cost estimates for new facilities were provided by a study conducted for the OPA by SNC Lavalin T&D. The report has been included in Section 11.3;
- Operations and maintenance costs were estimated as a percentage of the capital cost of the project, and would be incurred every year from the in-service date to the end of the projects useful life;
- Land cost was not included. Land costs are difficult to determine given the types of land and the variety of land holders that certain options described in this report may occupy; and
- Impact Benefit Agreements that may be negotiated between future projects proponents and impacted First Nations have not been estimated or included in the costs of options.

Procedure

To estimate the cost of transmission options to supply the North of Dryden sub-region, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to determine the capability of each option and the amount of capability of voltage control devices required to achieve the LMC;
2. Using unit costs for lines and stations, line lengths, number and types of new stations and/or station upgrades and voltage control requirements, capital, operations and maintenance costs of the system were calculated;
3. The amount of system generation that could be displaced after 2018, by associated local generation options for the subsystem was calculated; and
4. These capital, operations and maintenance costs and attributed costs for incremental system generation beginning in 2018, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

10.8.1 **Red Lake Subsystem Transmission Options**

Near-term Option - Upgrade of E4D and E2R

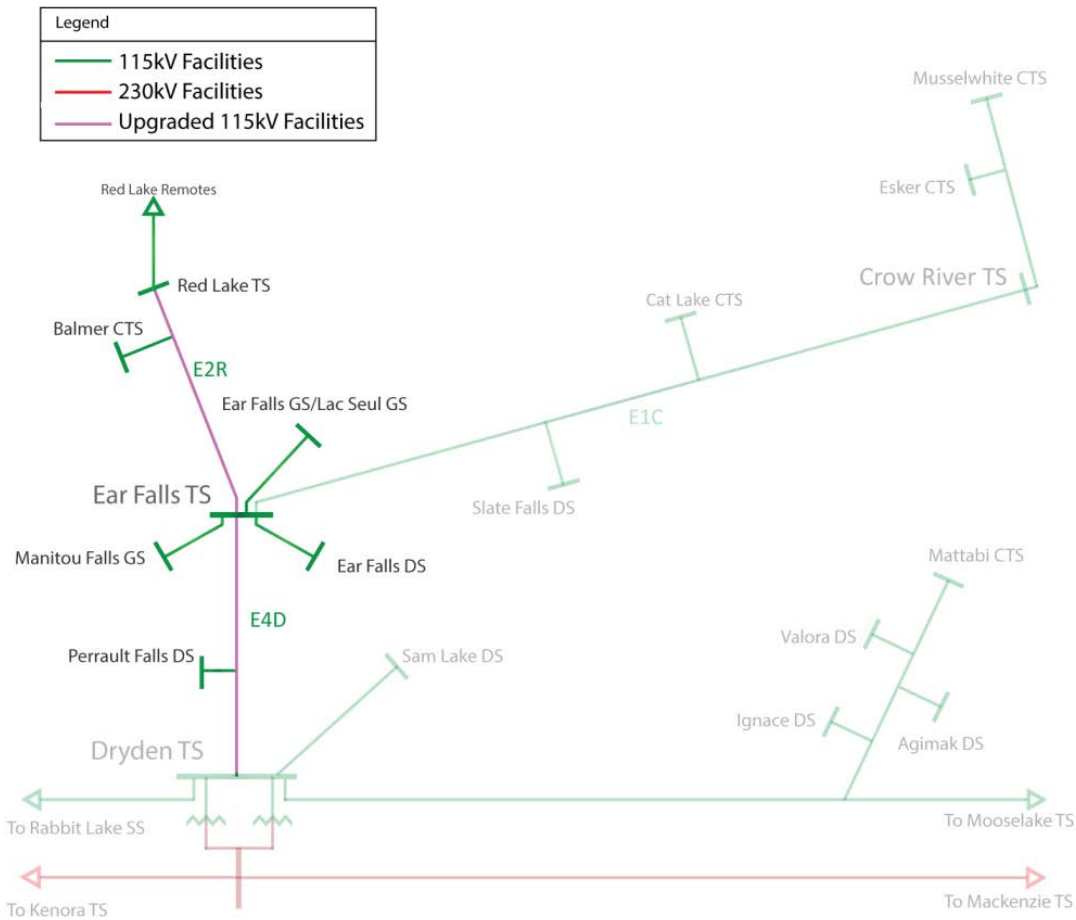
The existing lines serving the Red Lake subsystem are E4D, from Dryden to Ear Falls, and E2R, from Ear Falls to Red Lake. E4D has a thermal rating of 470 amps, and a transfer capability of 100 MVA (at 125 kV nominal voltage), while E2R a thermal rating of 420 amps, and a transfer capability of 91 MVA (125 kV nominal voltage). Based on dependable hydroelectric generation at Manitou Falls GS, Ear Falls GS and Lac Seul GS, and the current summer transmission line ratings, 85 MW of load can be served from Ear Falls TS. The Red Lake subsystem has an LMC of 61 MW, while the Pickle Lake subsystem has an LMC of 24 MW.

Hydro One has identified that E4D can be upgraded to a thermal rating of 670 amps, while E2R can be upgraded to 620 amps. After these line upgrades and the installation of an appropriate amount of voltage control at Ear Falls TS the Red Lake subsystem LMC will rise to 95 MW, assuming the Pickle Lake subsystem continues to be supplied solely from Ear Falls via circuit E1C and the LMC remains at 24 MW. A diagram of the upgrade of E4D and E2R is provided in Figure 27.

Table 85: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
Upgrade E4D and E2R	34 MW	95 MW	100 MW	109 MW	136 MW
and Transfer of Pickle Lake load to new line to Pickle Lake	35 MW	130 MW			

Figure 27: E4D and E2R Upgrade Diagram

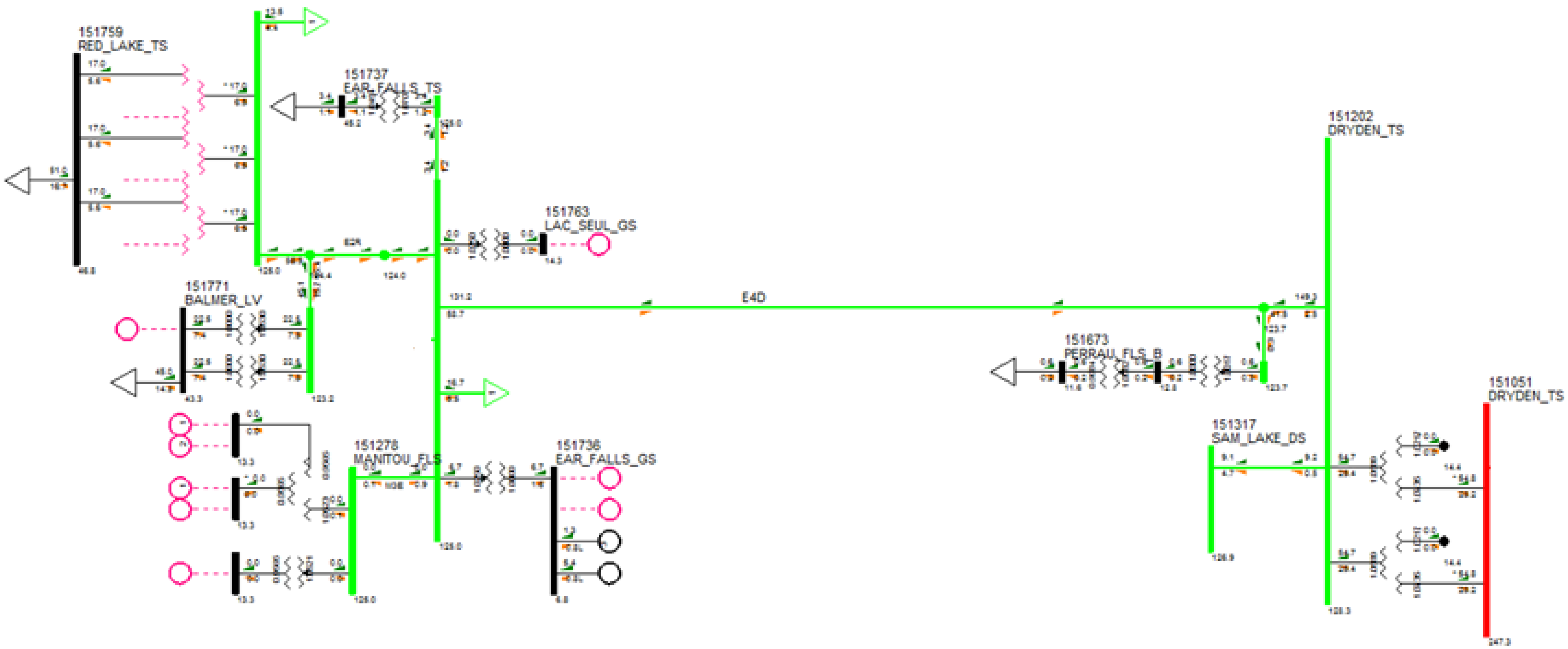


Hydro One has indicated that upgrading these lines as well as the installation of required voltage control devices could be completed within the near-term period. Table 86 below shows the cost breakdown of the upgrade option which includes the required voltage control devices. Figure 28 shows the load flow case during peak load. Ear Falls TS and Red Lake TS voltage is maintained in a healthy range of 120 kV to 125 kV.

Table 86: E4D and E2R Upgrade Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line Cost	0.0	5.0																		
Station Cost	0.0	10.5																		
O&M	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Annual Cost	0.0	15.7	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Annual Amortized Cost	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Cumulative PV	0.0	0.8	1.6	2.4	3.2	3.9	4.6	5.2	5.9	6.5	7.1	7.7	8.2	8.7	9.2	9.7	10.2	10.6	11.1	11.5

Figure 28: E4D and E2R Upgrade Red Lake Subsystem Configuration



Medium- and Long-term Option - 115 kV Line from Dryden TS to Ear Falls TS

This option is to build a new 115 kV single circuit line connecting at Dryden TS running to Ear Falls TS. A diagram of this option is provided in Figure 29. Because there are two local generation options for the Red Lake subsystem (30 MW, 60 MW), the 115 kV transmission option has been developed for an LMC of 160 MW and 190 MW. The option designed to have an LMC of 160 MW is comparable to the capability of the 30 MW Red Lake generation option and 190 MW LMC option is comparable to the 60 MW gas generation option, which meets the needs of the high scenario demand forecast. This difference in transmission LMC is determined by the voltage control requirements at Ear Falls TS.

Table 87: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 115 kV line from Dryden to Ear Falls with less compensation (160 MW)	30 MW	160 MW	100 MW	109 MW	136 MW
New 115 kV line from Dryden to Ear Falls with more compensation (190 MW)	60 MW	190 MW			

Figure 29: New 115 kV line to Ear Falls Diagram

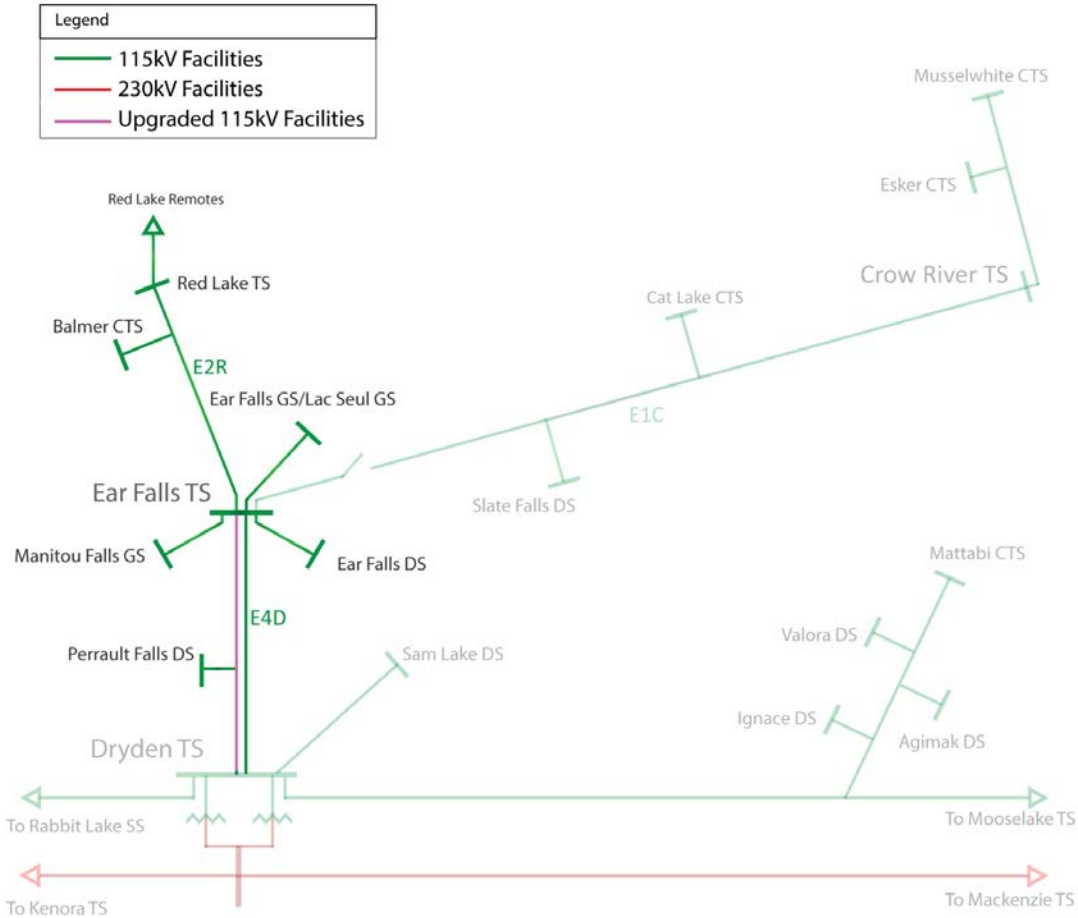


Figure 30, shows the peak load flow case for this option. Voltage at Ear Falls TS is maintained within a healthy range of 120 kV to 125 kV.

Table 88 and Table 89 summarize the annual cashflows and cumulative NPV cost for the options.

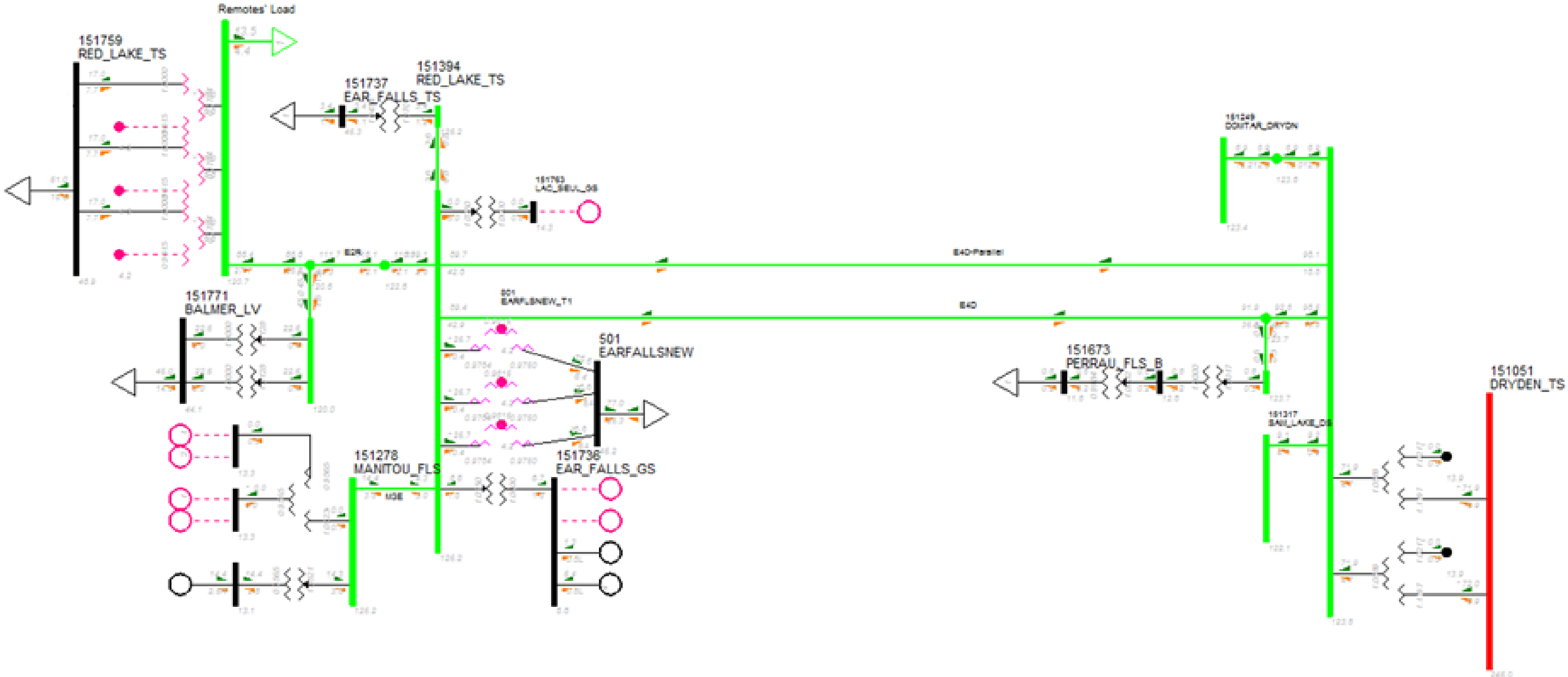
Table 88: 115 kV line to Ear Falls 160 MW LMC Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																	45.3			
Station cost																	45.6			
O&M																	0.9	0.9	0.9	0.9
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.8	0.9	0.9	0.9
Annual Amortized Cost																	5.1	5.1	5.1	5.1
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	5.4	7.9	10.3

Table 89: 115 kV line to Ear Falls 190 MW LMC Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																	45.3			
Station cost																	62.4			
O&M																	1.1	1.1	1.1	1.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	108.7	1.1	1.1	1.1
Annual Amortized Cost																	6.1	6.1	6.1	6.1
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	6.4	9.4	12.2

Figure 30: 115 kV Line Option Red Lake Subsystem Configuration



10.8.2 **Pickle Lake Subsystem Transmission Options**

The transmission options for the Pickle Lake subsystem include:

1. A new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker on the tap line and terminating at Crow River DS in Pickle Lake;

2. A new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker on the tap line and running to Pickle Lake terminating at Crow River DS or a new TS in the Pickle Lake area with a new 230/115 kV autotransformer at Crow River DS or a new station; and

3. A new single circuit line pre-built to 230 kV standards (230 kV structures, and hardware) and connecting it to M2D on the 115 kV system east of Dryden with an in-line breaker on the tap line. When additional capacity is required the line would be reterminated on the 230 kV system near Dryden (D26A) and a 230/115 kV autotransformer would be installed at Crow River DS or a new station in Pickle Lake.

For all of these transmission options, it is assumed that following the installation of a new line to Pickle Lake, the line E1C, connecting Ear Falls TS to Crow River DS (at Pickle Lake), would be normally open at Ear Falls. As a result, all customers in the Pickle Lake subsystem would be normally supplied by the new line to Pickle Lake. During sustained outages of the new line to Pickle Lake, some load in the Pickle Lake subsystem may be able to be restored by closing the normally E1C at Ear Falls TS and serving load in the Pickle Lake subsystem from Ear Falls TS. The amount of load that can be restored in the Pickle Lake subsystem from Ear Falls TS will be limited by the available capacity of circuits E4D and E1C.

115 kV Line to Pickle Lake

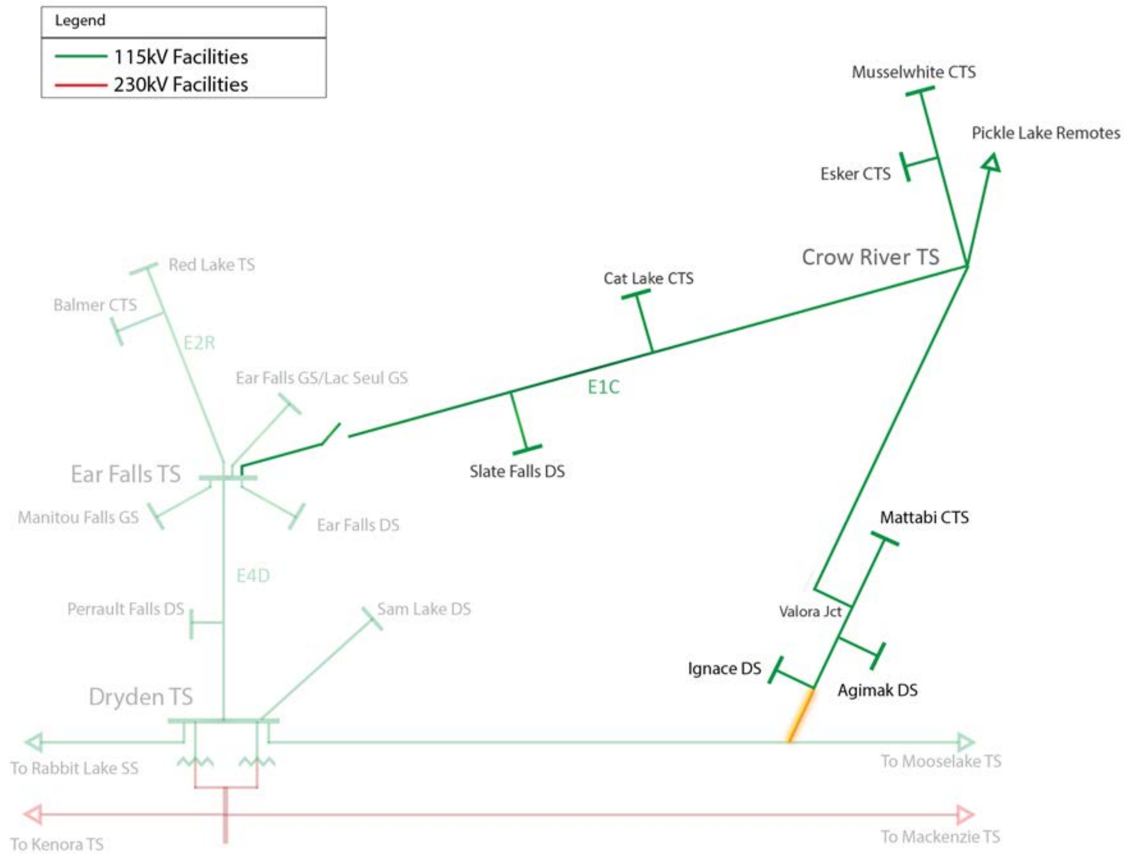
This option is to install a new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker and terminating at Crow River DS in Pickle Lake. Currently, there are a number of short sections of 29M1 between Ignace and Valora which have thermal ratings which are lower than the rest of the line. These sections will need to be upgraded to a thermal rating of at least 500 amps to allow the new line to Pickle Lake to have the required transfer capability.

Table 90: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 115 kV line from Valora to Pickle Lake	46 MW	70 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Figure 31 shows the Pickle Lake subsystem with this option, highlighting the section of 29M1 that would require upgrading.

Figure 31: New 115 kV line to Pickle Lake Diagram



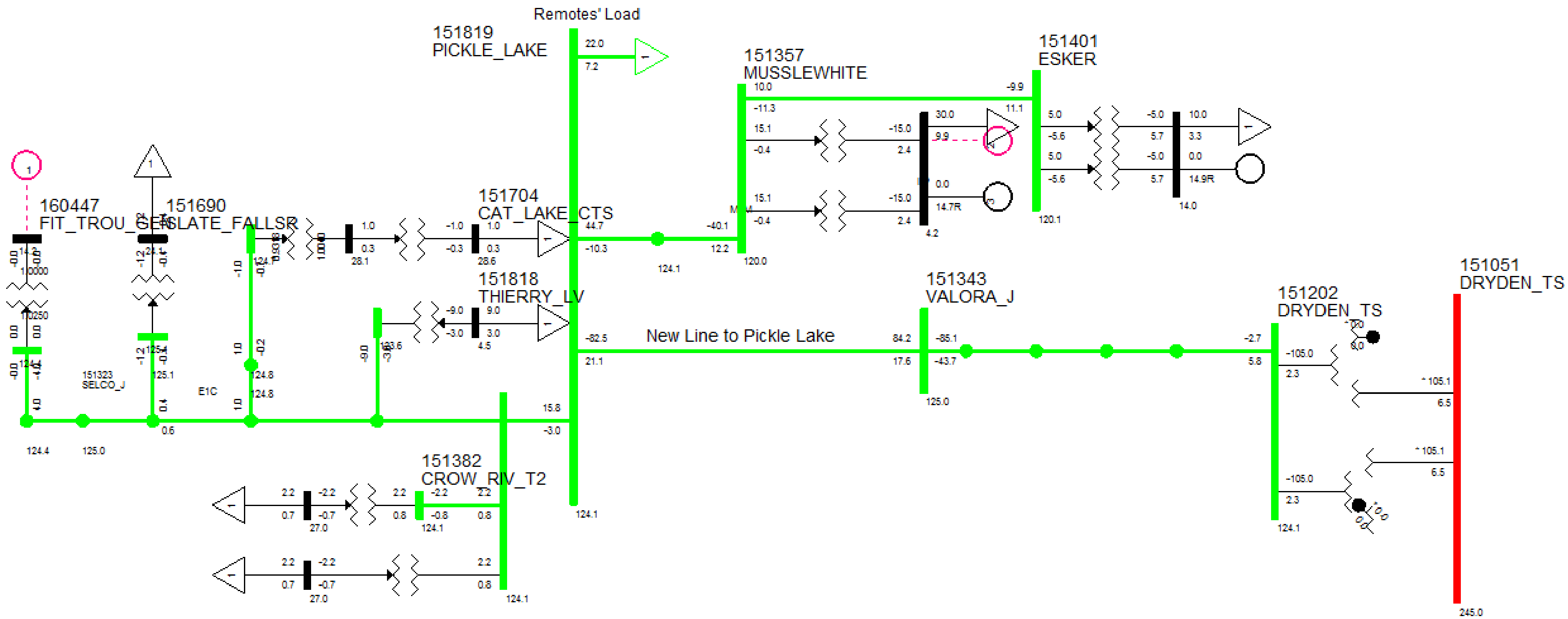
A summary of the cost for this option can be found in Table 91 below.

Figure 32 shows the load flow case during peak load. The Pickle Lake bus voltage is maintained in a healthy range of 120 kV to 125 kV.

Table 91: 115 kV line to Pickle Lake Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				104																
Station cost				22.5																
O&M				1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total Annual Cost	0.0	0.0	0.0	127.9	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Annual Amortized Cost				7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Cumulative PV	0.0	0.0	0.0	6.4	12.5	18.3	24.0	29.4	34.6	39.7	44.5	49.1	53.6	57.9	62.0	66.0	69.8	73.5	77.0	80.4

Figure 32: 115 kV Line Option Pickle Lake Subsystem Configuration



230 kV Line to Pickle Lake

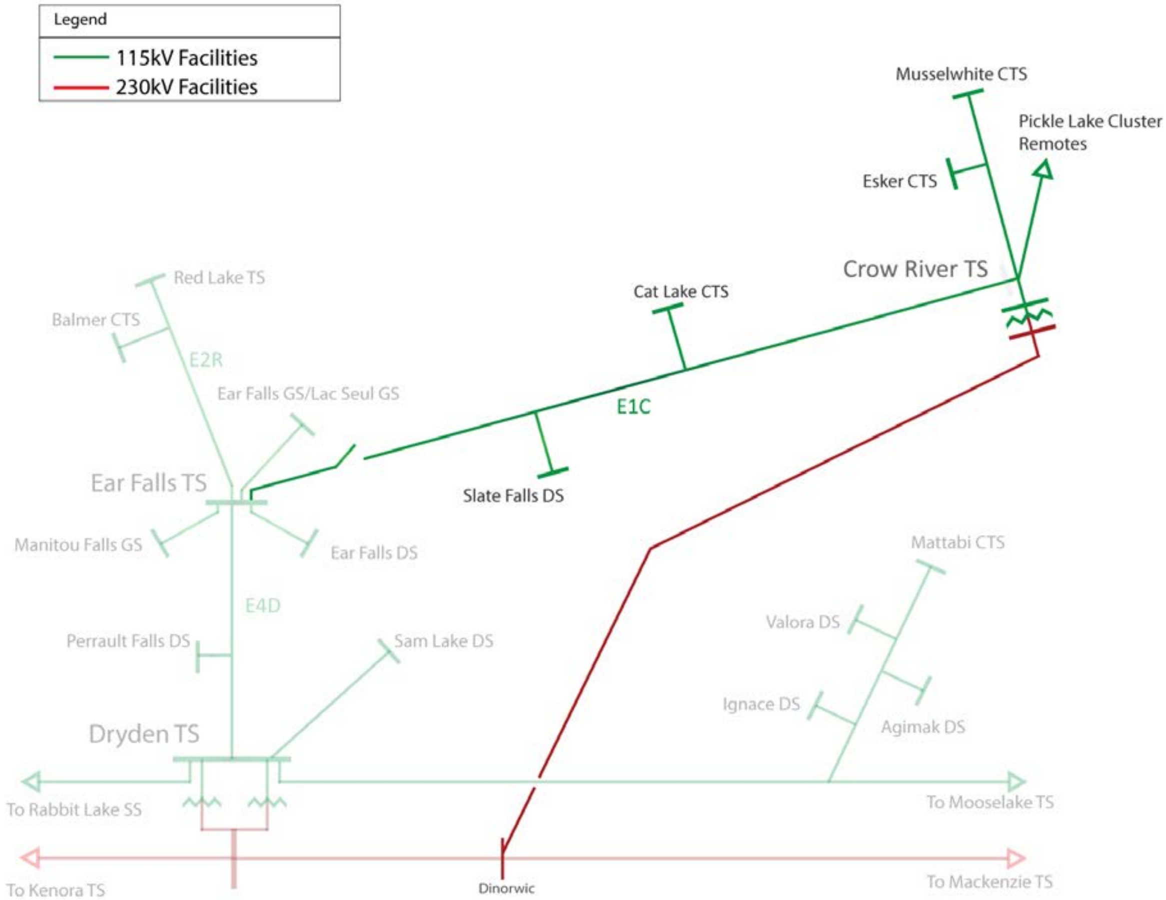
This option is to install a new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker running to Pickle Lake terminating at Crow River DS or at a new 230 kV station where a new 230/115 kV autotransformer will be installed.

Table 92: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 230 kV line from Dryden/Ignace to Pickle Lake	136 MW	160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

A diagram of this option is shown in Figure 33 below.

Figure 33: New 230 kV line to Pickle Lake Diagram



A summary of the cost for this option can be found in Table 93 and Table 94 below.

Table 94 shows an illustration of the peak load flow case for the new 230 kV line to Pickle Lake option. The voltage in the Pickle Lake area is maintained in a range of 240 kV to 245 kV, which helps to maintain voltages on existing and planned facilities within a healthy range.

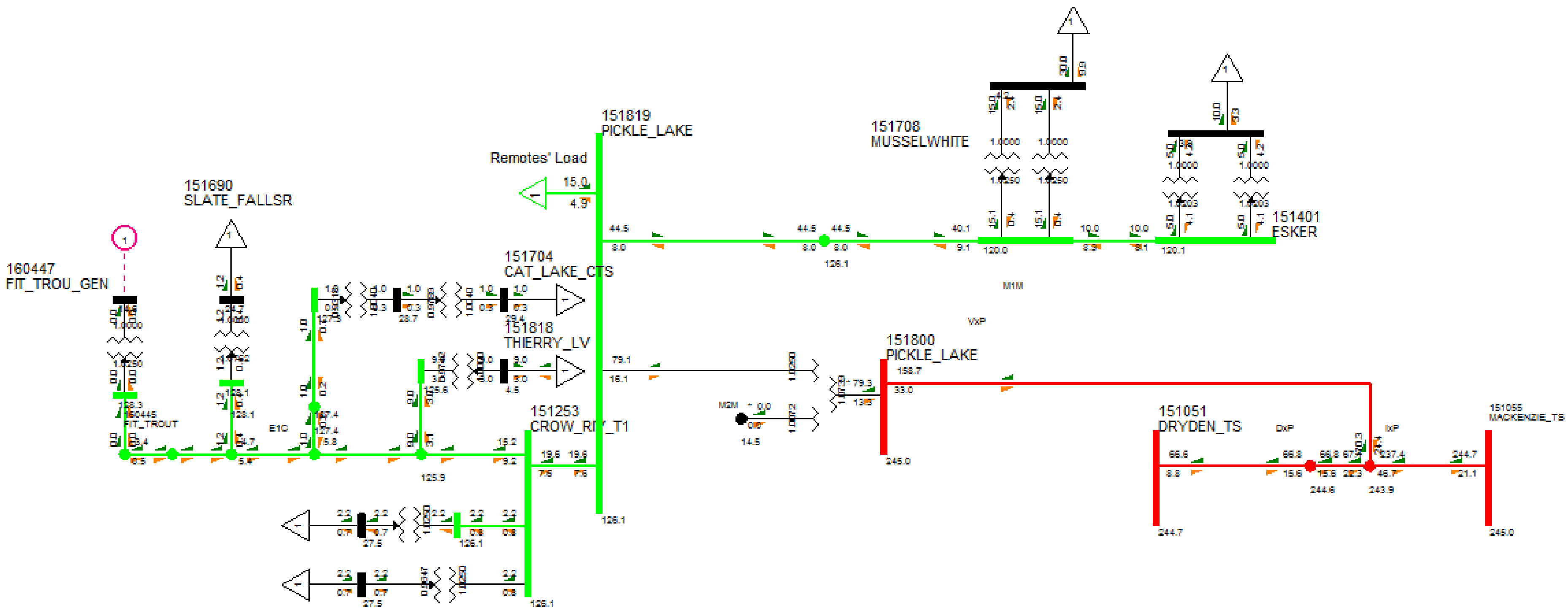
Table 93: 230 kV line to Pickle Lake Cost Summary for LMC up to 78 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				28.4																
O&M				1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Annual Cost	0.0	0.0	0.0	168.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Annual Amortized Cost				9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Cumulative PV	0.0	0.0	0.0	8.4	16.4	24.1	31.5	38.7	45.5	52.1	58.5	64.6	70.5	76.1	81.5	86.8	91.8	96.6	101.2	105.7

Table 94: 230 kV line to Pickle Lake Cost Summary for LMC up to 90 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				42.2																
O&M				1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Total Annual Cost	0.0	0.0	0.0	182.2	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Annual Amortized Cost				10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Cumulative PV	0.0	0.0	0.0	9.0	17.7	26.1	34.1	41.9	49.3	56.5	63.3	69.9	76.3	82.4	88.3	93.9	99.4	104.6	109.6	114.4

Figure 34: 230 kV Line Option Pickle Lake Subsystem Configuration



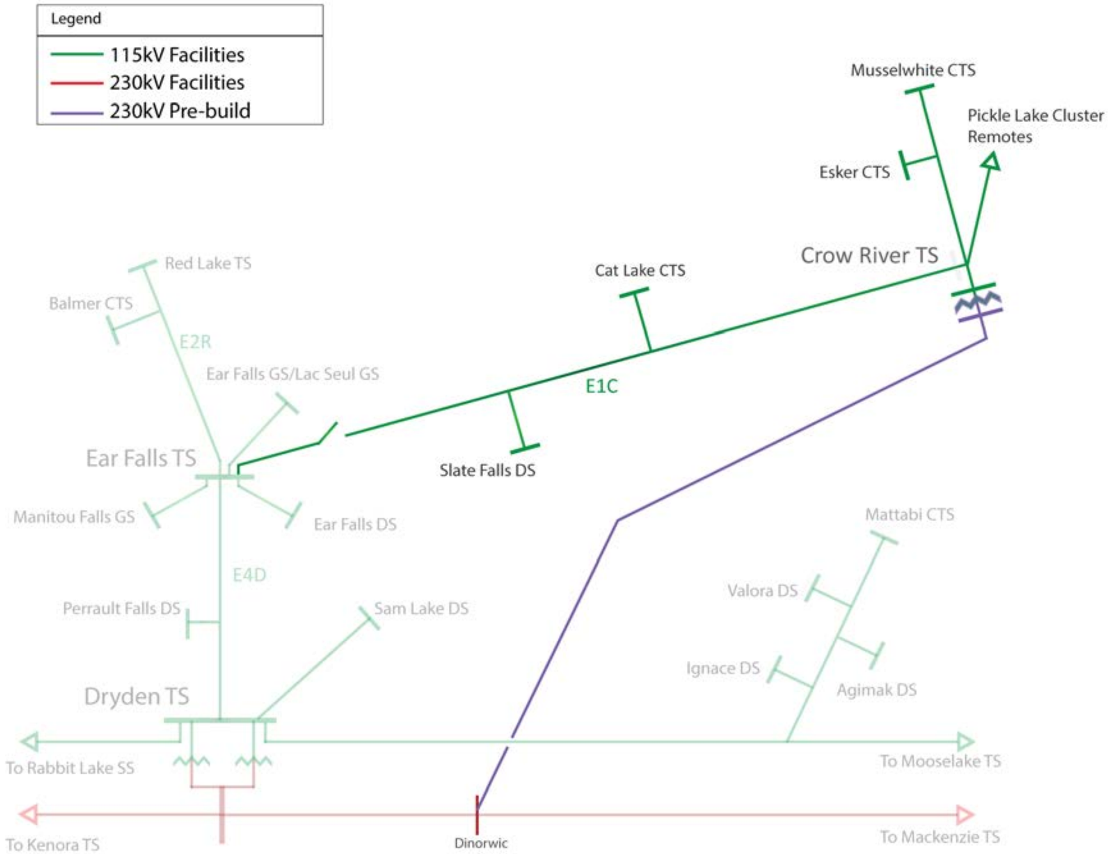
Pre-build 230 kV Line to Pickle Lake

This option would pre-build a new single circuit line to 230 kV standards (230 kV structures and hardware) and connect it to the 115 kV system on M2D east Dryden with an in-line breaker and running to Pickle Lake where it would terminate at Crow River DS. When additional capacity is required, the line would be reterminated on the regional 230 kV system (D26A) east of Dryden and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake.

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
Pre-build 230 kV line from Dryden/Ignace to Pickle Lake: Stage 1: operated at 115 kV Stage 2: operated at 230 kV	 46 MW 90 MW	 70 MW 160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Figure 35 provides a diagram of the area with this option, while Table 95 provides a summary of costs and timing for this option.

Figure 35: Pre-build 230 kV Line to Pickle Lake Option



Note: the above diagram illustrates the second stage configuration (operated at 230 kV).

Table 95: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 1

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				16.6																
O&M				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total Annual Cost	0.0	0.0	0.0	156.3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Annual Amortized Cost				8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Cumulative PV	0.0	0.0	0.0	7.8	15.2	22.4	29.3	35.9	42.3	48.4	54.3	60.0	65.5	70.7	75.8	80.6	85.3	89.7	94.1	98.2

Table 96: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 78 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost										14.0										
O&M										0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost										0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.1	1.6	2.1	2.6	3.0	3.5	3.9	4.3	4.7	5.1

Table 97: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 90 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost										26.0										
O&M										0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Annual Amortized Cost										1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0	3.9	4.8	5.6	6.4	7.2	8.0	8.7	9.4

10.8.3 **Ring of Fire Subsystem Transmission Options**

The following table summarizes the capability of various transmission options to meet the forecasted demand levels for the Ring of Fire sub-system for the reference, high, and low scenarios:

<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 colspan="3">East-West corridor</td><td rowspan="7">7 MW</td><td rowspan="7">29 MW</td><td rowspan="7">73 MW</td></tr>
<tr><td>115 kV line from Pickle Lake</td><td>60 MW</td><td>60 MW</td></tr>
<tr><td>230 kV line from Pickle Lake</td><td>78 MW</td><td>78 MW</td></tr>
<tr><td colspan="3">North-South corridor</td></tr>
<tr><td>230 kV line from Marathon TS</td><td>78 MW</td><td>78 MW</td></tr>
<tr><td>230 kV line from east of Nipigon</td><td>78 MW</td><td>78 MW</td></tr>
</table>

The options and costs of the options are discussed in further detail below.

115 kV Line Connection for Ring of Fire Remote Communities from Pickle Lake

In a scenario where mines at the Ring of Fire do not connect to the transmission system, it has been assumed that the 5 remote communities in the Ring of Fire subsystem would develop a connection to Pickle Lake, based on the findings of the draft Remote Community Connection Plan. This option is to build a 115 kV line from Pickle Lake to a point near Webequie FN passing near Neskantaga FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would connect by distribution lines to a new transformer station near Neskantaga FN, while Nibinamik FN and Webequie FN would connect by distribution line to a transformer station near Webequie FN.

Figure 36, provides an illustrative schematic of this option, while costs are provided in Table 98.

Figure 36: 115 kV Line from Pickle Lake to Matawa Remotes

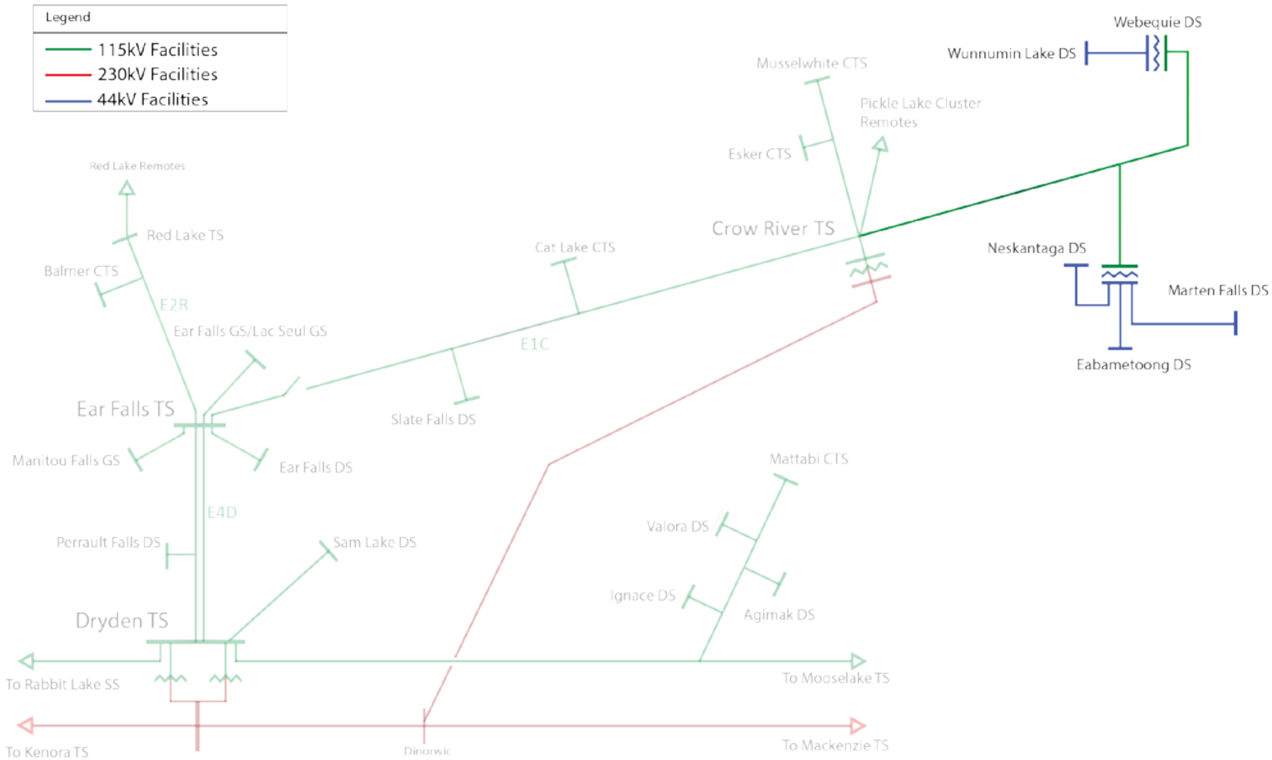


Table 98: 115 kV line from Pickle Lake to Ring of Fire Subsystem Remote Communities Cost Summary

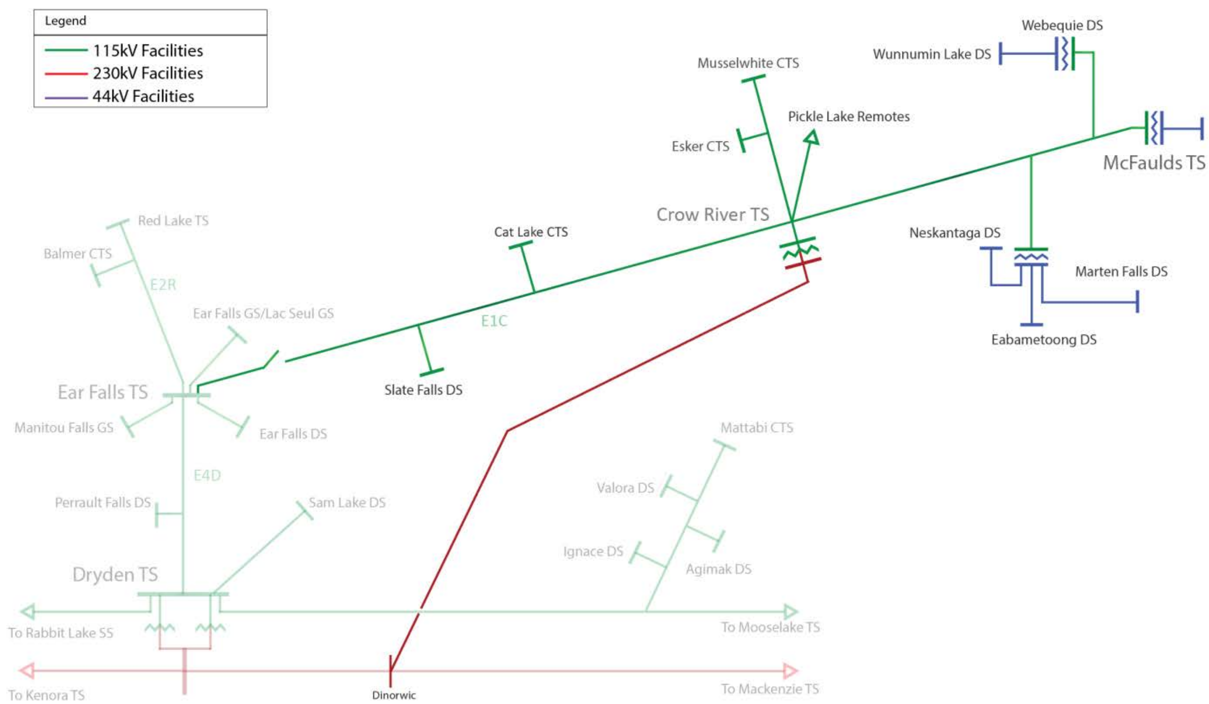
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						94.3														
Station cost						6.6														
O&M						1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	101.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Annual Amortized Cost						5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Cumulative PV	0.0	0.0	0.0	0.0	0.0	4.7	9.2	13.5	17.7	21.6	25.5	29.2	32.7	36.2	39.4	42.6	45.6	48.6	51.4	54.1
Line to Pickle Lake Portion	0.0	0.0	0.0	0.7	1.3	1.9	2.5	3.0	3.6	4.1	4.6	5.1	5.5	6.0	6.4	6.8	7.2	7.6	8.0	8.3
NPV with PL Line	62.4																			

115 kV Line from Pickle Lake to Ring of Fire

This option considers building a new 115 kV line from Pickle Lake to the Ring of Fire mining development area, and connecting the five remote communities in the Ring of Fire subsystem. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 60 MW of mining load at the Ring of Fire plus 7 MW of remote community load.

Figure 37, shows this option with the Pickle Lake subsystem.

Figure 37: 115 kV Line from Pickle Lake to Ring of Fire



A prorated portion of the costs for new a 230 kV transmission line and 230/115 kV transformer station from the Dryden area to Pickle Lake is included in the cost of this option because it is required for this option to be undertaken as is shown in the cost summary in Table 99.

Figure 38 provides the peak load flow for the North of Dryden sub-region, illustrating that voltages throughout the subsystem are maintained in a healthy range of 120 kV to 125 kV.

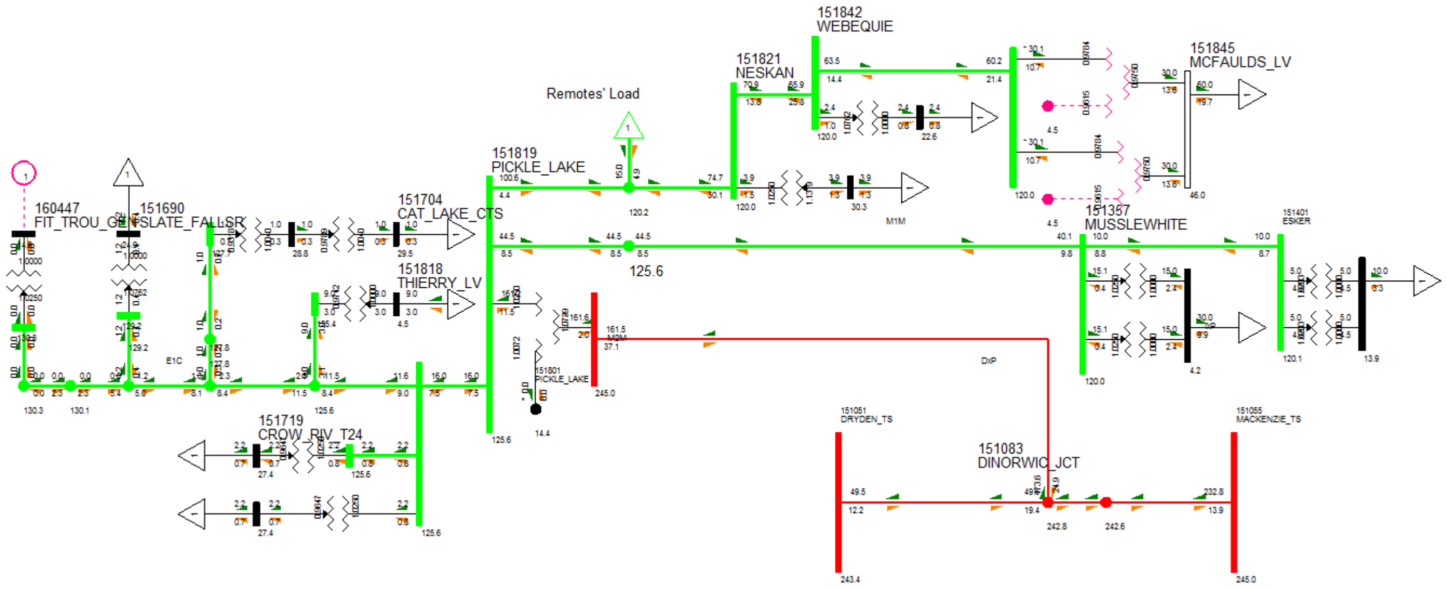
Table 99: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 29 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						132														
Station cost						13.6														
O&M						1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	147.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Annual Amortized Cost						8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Cumulative PV	0.0	0.0	0.0	0.0	0.0	6.8	13.3	19.5	25.5	31.3	36.9	42.2	47.4	52.3	57.1	61.6	66.0	70.3	74.3	78.2
Line to Pickle Lake Portion	0.0	0.0	0.0	2.2	4.3	6.3	8.2	10.1	11.9	13.6	15.3	16.9	18.4	19.9	21.3	22.7	24.0	25.2	26.4	27.6
NPV with PL Line	105.8																			

Table 100: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 51 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						132														
Station cost						23.2														
O&M						1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	157.1	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Annual Amortized Cost						8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	7.2	14.1	20.8	27.2	33.4	39.3	45.0	50.5	55.8	60.8	65.7	70.4	74.9	79.2	83.4
Line to Pickle Lake Portion	0.0	0.0	0.0	3.2	6.3	9.2	12.1	14.8	17.5	20.0	22.4	24.8	27.0	29.2	31.3	33.3	35.2	37.0	38.8	40.5
NPV with PL Line	123.9																			

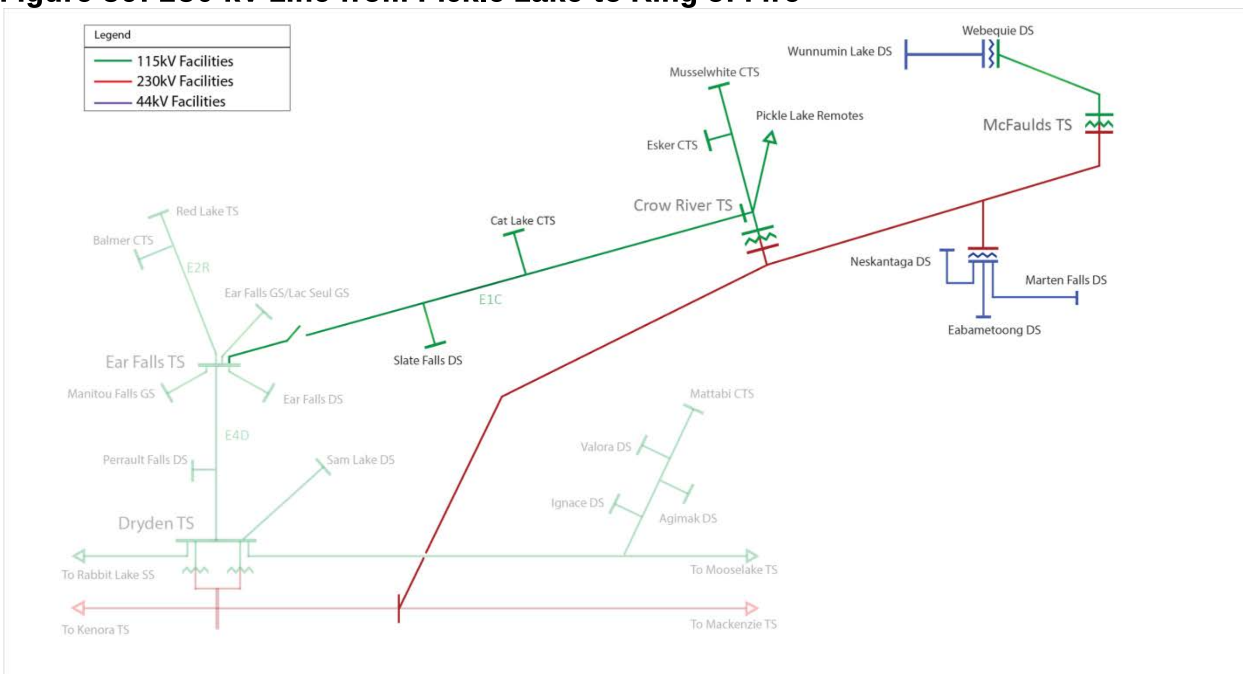
Figure 38: 115 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration



230 kV Line from Pickle Lake to Ring of Fire

This option considers building a new 230 kV single circuit line from a new 230 kV station at Pickle Lake to the Ring of Fire, and a new 230/115 kV TS near Neskantaga FN and at the Ring of Fire. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. This line would enable the connection of the five Matawa remote communities in the Ring of Fire subsystem as well as serve the high growth scenario (MW) for mining load at the Ring of Fire. Figure 39 shows the Pickle Lake and Ring of Fire subsystems with a new 230 kV line from the Dryden area to Pickle Lake and this option for a new 230 kV line from Pickle Lake to the Ring of Fire. Figure 39, shows this option implemented with the Pickle Lake subsystem.

Figure 39: 230 kV Line from Pickle Lake to Ring of Fire

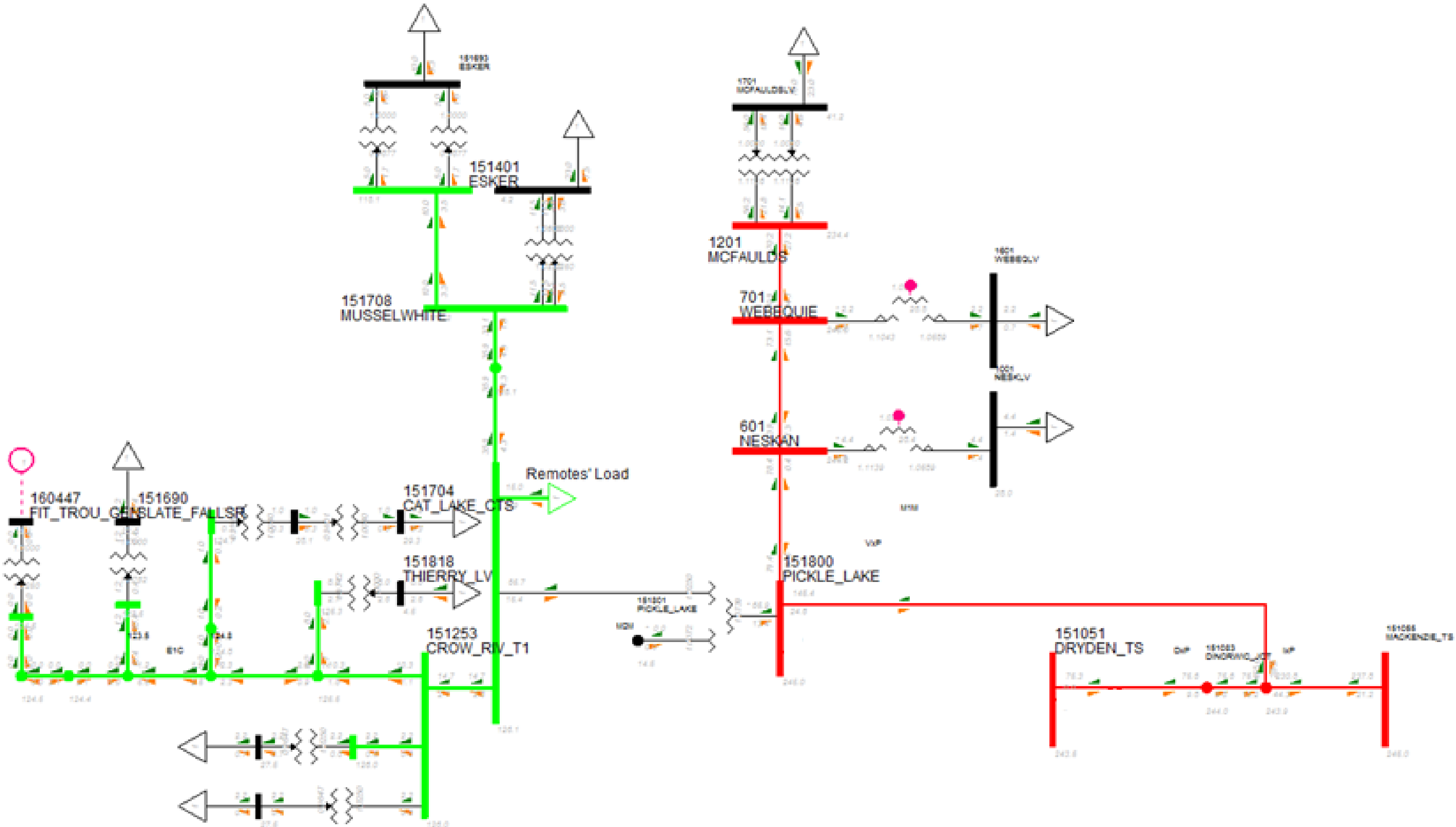


A prorated portion of the costs for new a 230 kV transmission line and station from the Dryden area to Pickle Lake is included in the cost of this option, as shown in the cost summary in Table 101 below.

Table 101: 230 kV line from Pickle Lake to Ring of Fire Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						165														
Station cost						30.4														
O&M						2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	197.7	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Annual Amortized Cost						11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Cumulative PV	0.0	0.0	0.0	0.0	0.0	9.1	17.8	26.2	34.3	42.0	49.5	56.6	63.5	70.2	76.5	82.7	88.6	94.2	99.7	104.9
Line to Pickle Lake Portion	0.0	0.0	0.0	4.1	8.0	11.8	15.4	18.9	22.2	25.4	28.5	31.5	34.4	37.1	39.7	42.3	44.7	47.1	49.4	51.5
NPV with PL Line	156.4																			

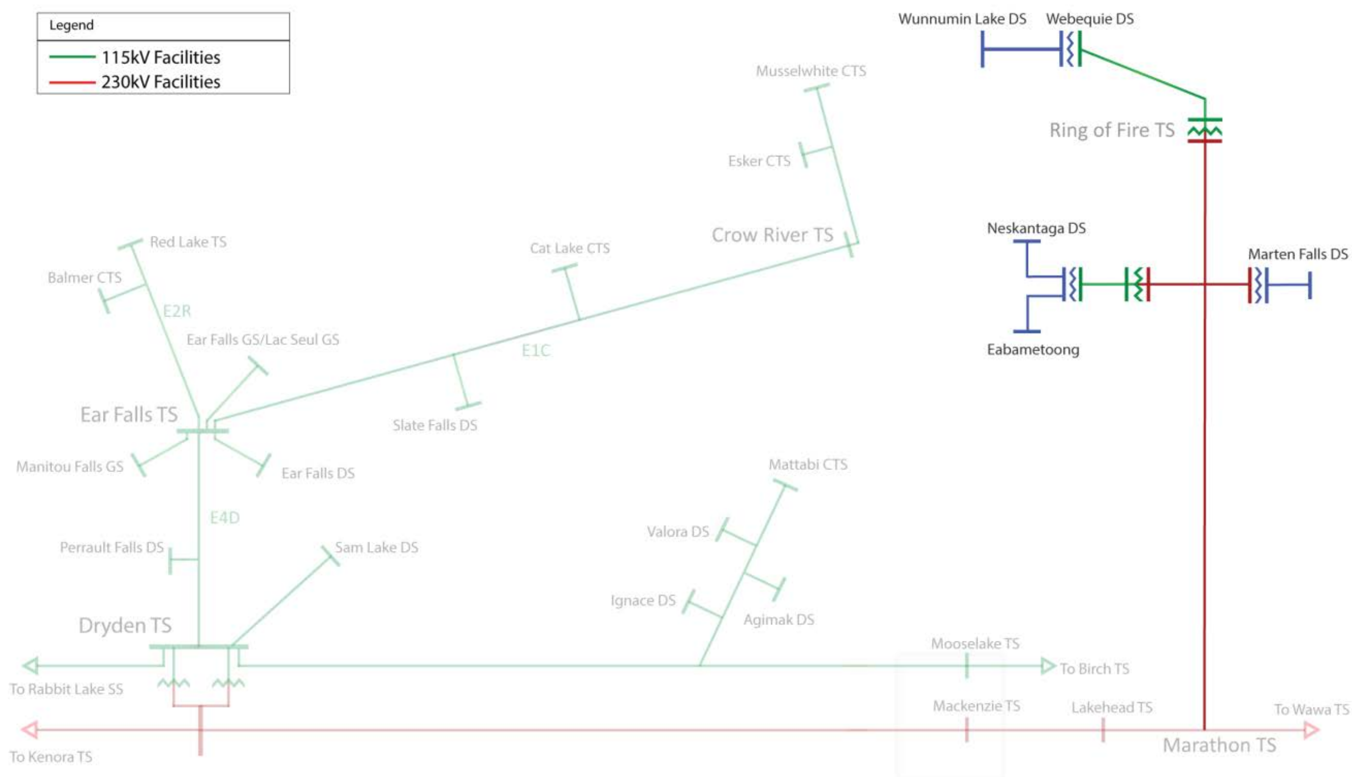
Figure 40: 230 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration



230 kV Line from Marathon TS or east of Nipigon to Ring of Fire

Given the potential for a new all season road to serve the Ring of Fire mining development area from around Nakina, this option was developed to leverage the availability of the all season road assuming they can share a common right of way from Nakina. The existing transmission supply serving the Long Lac\Nakina area is the single circuit 115 kV line A4L, which has insufficient capability to serve the forecast load growth of the Ring of Fire subsystem. Therefore, a new 230 kV single circuit transmission line from either Marathon TS or east of Nipigon would be required for this option. These options have similar line lengths and are expected to have approximately the same costs. A diagram of this option is provided in Figure 41 below.

Figure 41: 230 kV Line from Marathon or East of Nipigon to Ring of Fire

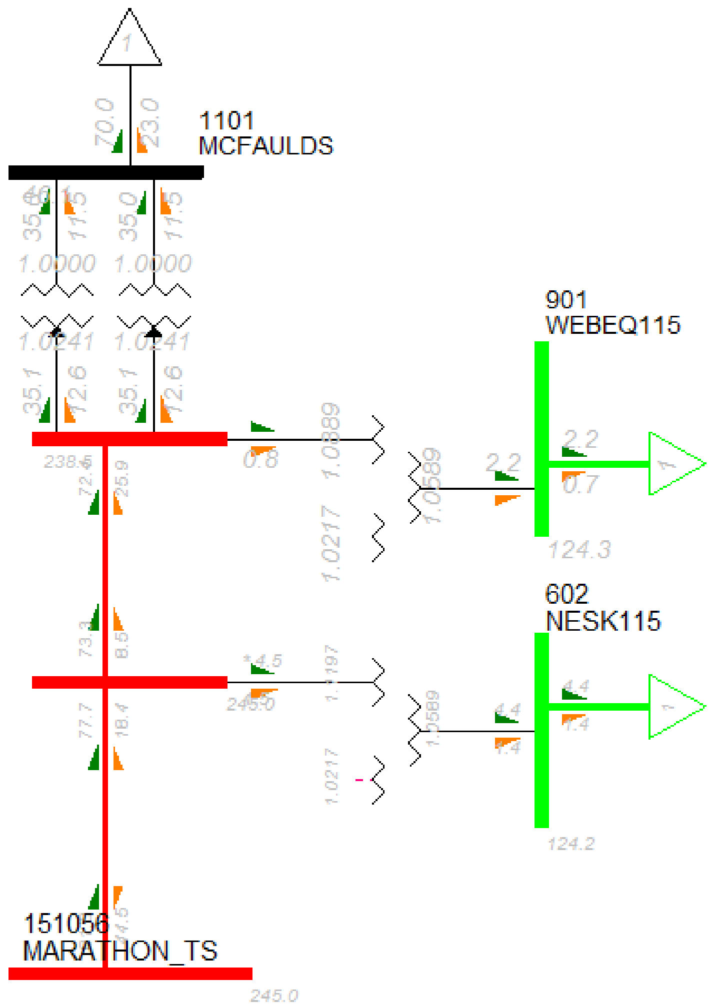


The LMC of the Ring of Fire subsystem for this option is 77 MW. This includes 7 MW for the communities on the line as well as 70 MW at the Ring of Fire. A summary of the cost for this option can be found in Table 102 below.

Table 102: 230 kV line from Marathon TS or east of Nipigon to Ring of Fire Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						262														
Station cost						64.7														
O&M						3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	330.0	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Annual Amortized Cost						18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Cumulative PV	0.0	0.0	0.0	0.0	0.0	15.1	29.7	43.7	57.2	70.1	82.6	94.6	106.1	117.1	127.8	138.0	147.9	157.3	166.4	175.2
NPV	175.2																			

Figure 42: 230 kV Line from Marathon Option Ring of Fire Subsystem Configuration



11 OTHER REPORTS PROVIDED

11.1 IESO/OPA North of Dryden and Remote Communities Study – May 2012

11.2 Draft Remote Community Connection Plan – August 2012

11.3 Unit Cost Estimates for Transmission Lines and Facilities in Northern Ontario and the Far North – SNC Lavalin T&D, 2011

11.4 Draft Remote Community Connection Plan – August 2014