GREENSTONE-MARATHON
INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | June 30, 2016

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Integrated Regional Resource Plan

Greenstone-Marathon Area

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066, and was prepared by the IESO on behalf of the Greenstone-Marathon Sub-region Working Group ("Working Group"), which included the following members:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The preparation of the IRRP included extensive discussions with industrial developers, as well as engagement with communities who may have interest in the potential industrial developments or options for providing the required electrical supply. The Working Group would like to acknowledge and thank the members of two Local Advisory Committees which were established to provide community input into the development of the IRRP. Their input provided valuable guidance in shaping the electrical supply options.

The Working Group assessed the adequacy of electricity supply to customers in the Northwest Ontario Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers customer needs, community input, opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions. Based on all the planning information provided, an implementation plan was developed. The implementation plan seeks to maintain flexibility in order to accommodate changes in key assumptions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. As the recommendations are directly related to a few large industrial developments, the onus lies with those developers to initiate the implementation of the plan. Working Group members cannot commit to any capital expenditures until the necessary commercial agreements, regulatory and other approvals to implement recommended actions are obtained by the appropriate parties.

In addition to the requirements set out in the IESO's licence, analysis that was requested from communities and was determined by the IESO to provide value to the overall context of electricity planning for the Greenstone-Marathon Sub-region, has also been included in this report.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviation	Description
ACSR	Aluminum Conductor, Steel Reinforced
AZA	Animbiigoo Zaagi'igan Anishinaabek
AEMO	Australian Energy Market Operator
BZA	Biinjitiwaabik Zaaging Anishinaabek
BNA	Bingwi Neyaashi Anishinaabek
CCRA	Connection Cost Recovery Agreement
CDM	Conservation and Demand Management
C/I	Commercial and Industrial
CVNW	Common Voice Northwest Energy Task Force
CGS	Customer Generating Station
DG	Distributed Generation
DR	Demand Response
DSC	Distribution System Code
ERCOT	Electric Reliability Council of Texas
EA	Environmental Assessment
EUE	Expected Unserved Energy
GS	Generating Station
Hydro One	Hydro One Networks Inc.
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LUEC	Levelized Unit Energy Cost
MVA	Mega Volt Ampere

Abbreviation	Description
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOMA	Northwestern Ontario Municipal Association
NPCC	Northeastern Power Coordinating Council
NPV	Net Present Value
NUG	Non-Utility Generator
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report
RAS	Remedial Action Scheme (Formerly Special Protection System)
Region	Northwest Ontario
RIP	Regional Infrastructure Plan
Scoping Report	Scoping Process Outcome Report
SIA	System Impact Assessment
SS	Switching Station
STATCOM	Static Synchronous Compensators
Sub-region	Greenstone-Marathon Area as a sub-region of the Northwest Ontario Region
SVC	Static Var Compensators
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer
VCR	Value of Customer Reliability
VOLL	Value of Lost Load
WZI	Waaskiinaysay Ziibi Inc.
Working Group	Technical Working Group for Greenstone-Marathon Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP" or "Plan") for the Greenstone-Marathon Sub-region addresses the electricity needs for the sub-region over the next 20 years. The IRRP was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group for the Greenstone-Marathon Sub-region composed of the IESO, Hydro One Distribution and Hydro One Transmission[1] (the "Working Group").

The Greenstone-Marathon Sub-region includes several First Nation communities: Red Rock Indian Band, Bingwi Neyaashi Anishinaabek ("BNA"), Biinjitiwaabik Zaaging Anishinaabek ("BZA"), Animbiigoo Zaagi'igan Anishinaabek ("AZA"), Long Lake #58, Ginoogaming, Aroland, Pays Plat, Ojibways of the Pic River and Pic Mobert. The area also encompasses the Town of Marathon, the Municipality of Greenstone, and the Townships of Nipigon, Manitouwadge, Schreiber, Terrace Bay, Hornepayne and White River. The area covered by the Greenstone-Marathon IRRP is a sub-region of the Northwest Ontario Region identified through the Ontario Energy Board ("OEB" or "Board") regional planning process.

The regional planning process considers the local needs of a region over a 20-year planning horizon, and seeks to ensure cost-effective, reliable electricity supply to Ontario's communities over the long term. An IRRP takes into consideration, among other things, existing electricity infrastructure in an area, anticipated growth, and electricity requirements. The IRRP then establishes a guide for electricity infrastructure investments, resource development, and procurement decisions for a region, and may include conservation, generation, transmission and/or distribution.

In early 2015, the Municipality of Greenstone and the electricity customers in the area advised the Working Group that the 18-month timeline for IRRPs established by the OEB could not satisfy the timeline of industrial developments anticipated in the area. Given that the forecast growth in the sub-region is driven by the potential for large industrial development, the Municipality and the electricity customers requested that an interim planning report be developed to align with near-term development timelines. The Greenstone-Marathon Interim IRRP ("Interim IRRP") was released June 22, 2015 for the purpose of facilitating critical decision making for customers in a manner that accommodates near-term development timelines,

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

considers electricity supply needs in the area, and ensures that the electricity system can support the pace of development.

This IRRP for the Greenstone-Marathon Sub-region updates the options and recommendations established for the near term in the Interim IRRP, and extends the analysis to include the medium term (5-10 years) and long term (10-20 years). This IRRP is organized as follows:

- A summary of the recommended plan for Greenstone-Marathon is provided in Section 2;
- The process used to develop the IRRP is discussed in Section 3;
- The context for electricity planning in Greenstone-Marathon and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management ("CDM" or "conservation") and distributed generation ("DG") assumptions are described in Section 5;
- Needs in Greenstone-Marathon are presented in Section 6;
- Alternatives and recommendations for meeting near-term needs are addressed in Section 7;
- Near-term plan recommendations are set out in Section 8;
- Options for the medium and long term are described in Section 9;
- A summary of community and stakeholder engagement to date is provided in Section 10; and
- A conclusion is provided in Section 11.

2. The Integrated Regional Resource Plan

The Greenstone-Marathon IRRP addresses the area's electricity needs over the next 20 years. The IESO prepared the IRRP based on consideration of integrated planning criteria (reliability, cost, feasibility, flexibility, and social and environmental considerations), and based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP uses a scenario-based analysis to identify requirements based on major industrial development for the near term (present-5 years), medium term (5-10 years) and long term (10-20 years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required. In the near term, it seeks to maximize the use of the existing electricity system, where it is economic to do so.

The IRRP identifies least societal cost options to assist customers and proponents in near-term decision making for meeting the overall electricity needs of the Greenstone-Marathon Sub-region. The IRRP identifies specific investments that respect development lead times, while meeting the various needs in the area and considering feedback from local communities.

For the medium and long term, the IRRP identifies a number of alternatives to meet needs. The medium and long-term needs identify developments that may materialize in the future and could result in cost, environmental, and societal synergies with the identified near-term options. For needs that are forecast to occur in the long term, it is not necessary (given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead, near-term actions are identified to develop alternatives and engage with local communities, to gather information and lay the groundwork for future options. Actions identified for the near term will be directionally consistent with and inform the actions for the medium to long term.

Below is a summary of needs and recommended actions.

2.1 Near-Term Plan Summary

The plan to meet the near-term needs of electricity customers in the Greenstone-Marathon Sub-region was developed considering the planning criteria, including reliability, cost, feasibility, and maximizing the use of the existing electricity system where it is economic to do so.
The near-term needs for the area consist of providing additional capacity to supply industrial development, while considering reliability and service quality requirements for the individual industrial developments.

The recommended elements of the near-term plan depend primarily on the outcome of two potential industrial customers: a mining development in Geraldton (the "Geraldton mine"), and a major gas to oil pipeline conversion project. The Geraldton mine developers have publically communicated an in-service date of 2019, and the major gas to oil pipeline conversion project developers have publically communicated an in-service date of 2020. A scenario-based planning approach has been taken in order to provide recommendations that address the different potential development scenarios that may arise in the area.

2.2 Recommended Actions for the Near Term

Since publishing the Interim IRRP in June, 2015, the Geraldton mine developers notified the IESO of adjustments to their project schedule and scope. Specifically, they now expect to commission in a single stage in 2019, as opposed to two stages in 2018 and 2020 (which was considered in the Interim IRRP). The IESO's recommendations have been revised accordingly.

The IESO recommends a staged approach to accommodate forecast demand from the Geraldton mine and the pumping stations from the gas to oil pipeline conversion project. Stage 1 economically maximizes the use of the existing system to supply the Geraldton mine, while Stage 2 recommends the incremental infrastructure expansion necessary to accommodate the additional demand from the pumping stations.

Stage 1 – Coincident with the Geraldton mine in-service

- Install +40 MVar of reactive compensation at the Geraldton mine
- Install a customer-based grid-connected gas-fired generation plant of sufficient redundancy to meet the risk tolerance of the mining company. A 2x10 MW reciprocating engine plant was used for costing, and would meet North American standards.[2]

[2] The IESO has assumed N-1 reliability of the plant (single redundant unit), consistent with North American electricity reliability standards. If the generation can operate in island-mode, it may be advantageous to pursue due to the inherent supply diversity that it offers. The customer may also wish to investigate the applicability of conservation incentives that the IESO offers to compliment this option.

Figure 2-1: Recommended Actions – Stage 1

Stage 2 – Coincident with the gas-oil pipeline conversion project

- Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, and a new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac Transformer Station ("TS") to be in-service coincident with the pumping stations loads.
- Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to be in-service coincident with the incorporation of the pumping stations as part of the major pipeline conversion project.

Figure 2-2: Recommended Actions – Stage 2

The following should be noted:

- If the Geraldton mine and the major gas to oil pipeline conversion project do not materialize or do not choose to connect to the power system, no new system enhancements are required to supply distribution customer growth.[3]
- If the Geraldton mine materializes, but the major gas to oil pipeline conversion project does not materialize or does not choose to connect to the power system, only Stage 1 is required.
- If the Geraldton mine and the major gas to oil pipeline conversion project choose to connect to the power system, Stage 1 and Stage 2 are required.

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[3] It should be noted that even with growth in population and employment due to the industrial customer developments, the distribution customer demand does not increase to the point where the existing system would require a capacity increase.

- If the Geraldton mine and the major gas to oil conversion project choose to connect to the power system, it may be advantageous to the Geraldton mine to advance the new 230 kV line from Stage 2 to reduce or avoid its gas generation costs associated with Stage 1.
- The implementation of Stage 1 and Stage 2 of the near-term plan requires a commercial agreement to be established between the future service provider and the new customers before development work can proceed.
- Further changes to timelines that have been communicated to the IESO by industrial developers may alter the timing and scope of near-term recommendations.

2.3 Medium- and Long-Term Plan Summary

In the medium and long term, the likely drivers of future electricity demand for the Greenstone-Marathon planning area are:

- Additional mining claims in the Greenstone area, specifically near Beardmore (the "Beardmore mine"),
- The potential supply option of utilizing a north-south corridor to supply the Ring of Fire and remote communities of Eabametoong, Marten Falls, Neskantaga, Nibinamik, and Webequie, and
- Community-level energy efficiency opportunities in the Town of Marathon to reduce electric heating demand.

A scenario-based planning approach has also been taken for the medium and long term to address the different potential development scenarios for the area.

2.4 Actions to Maintain Flexibility for the Medium and Long Term

The following actions are proposed to maintain flexibility for accommodating additional growth, within the study area:

- Mine developers in Greenstone retain the option of upgrading circuit A4L from Alexander Switching Station ("SS") to Beardmore TS as an economic alternative for supplying the Beardmore mine and additional mining in Greenstone. Mine developers should engage Hydro One, the transmission owner of circuit A4L, recognizing that a lead-time of approximately five years is required if they wish to pursue this option.
- Those investigating a multi-use infrastructure corridor to the Ring of Fire consider the need for a new transmission line, as outlined in this Plan. The IESO is available to provide planning advice associated with a new transmission line on this corridor. The

IESO will also update electricity plans associated with this corridor as additional information becomes available.

- The Town of Marathon conduct a detailed study of community energy options related to cogeneration. The IESO can support studies within the context of electricity planning, demand, and reliability, as well as IESO-coordinated conservation programs and funding, if applicable.

The IESO does not have the authority to direct or implement these actions on behalf of the indicated parties. These actions are documented to provide customers, communities, and stakeholders with the IESO's independent assessment of the technically feasible and least societal cost options for meeting the various needs in the area.

3. Development of the Integrated Regional Resource Plan

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board[4] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code ("TSC") and Distribution System Code ("DSC") in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and

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[4] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

distribution solutions, or whether a straightforward "wires" solution is the only option such that a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. The Scoping Assessment assesses what type of planning is required for each region. There may also be regions where infrastructure investments do not require regional coordination and so can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. It should be noted that an RIP may be initiated after the Scoping Assessment or after the completion of all IRRPs within a planning region; the transmitter may also initiate and produce a RIP report for every region. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a 2-week comment period prior to finalization.

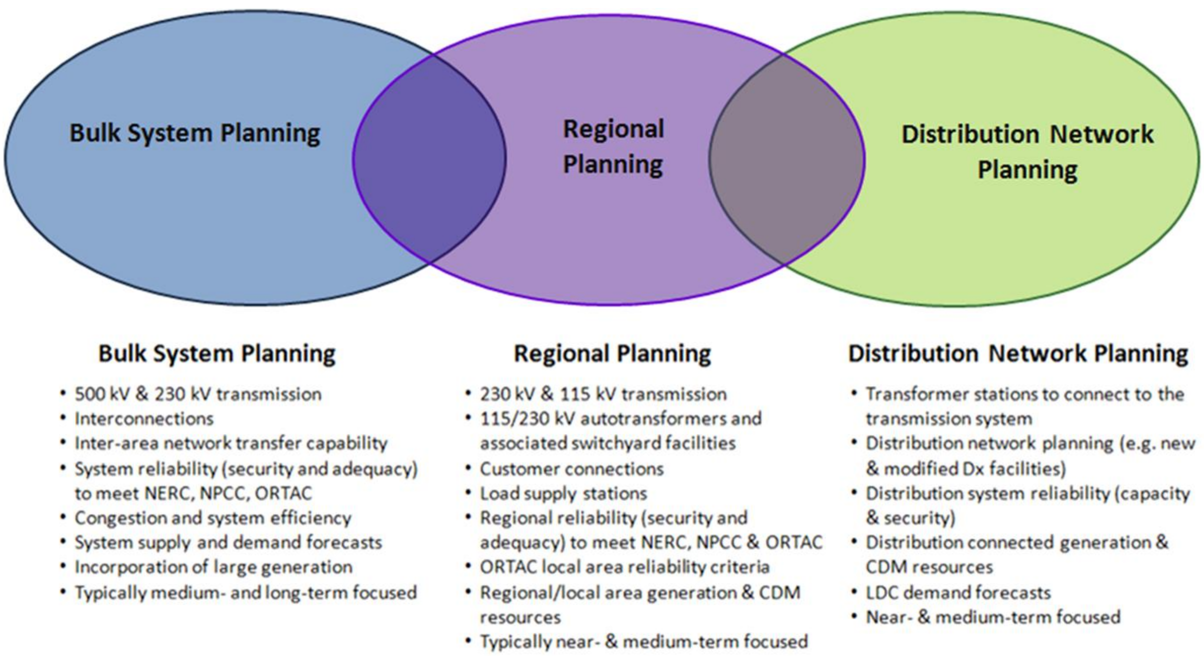
The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, conservation and energy management purposes, as information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by Local Distribution Companies ("LDCs"), considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning as it is the link between all levels of planning.

Figure 3-1: Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO’s Approach to Integrated Regional Resource Planning

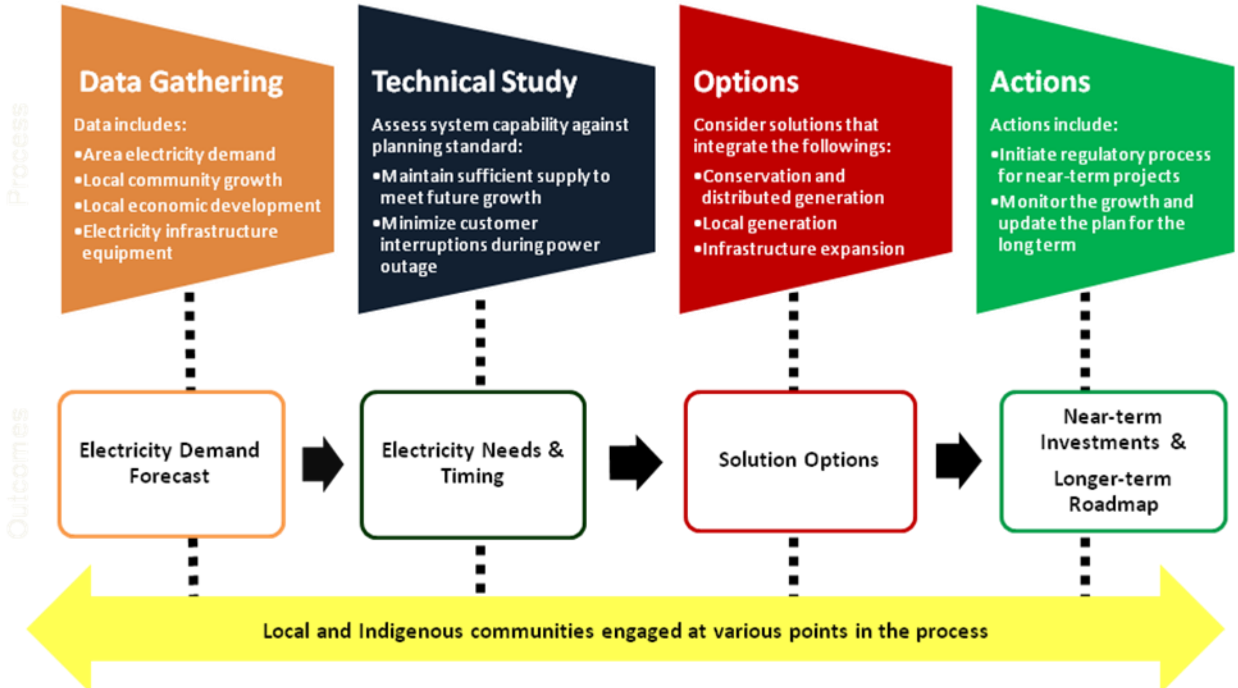
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends in a region, so that near-term actions are developed within the context of a longer-term vision. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

Planning in northwestern Ontario requires a unique approach. In southern Ontario, most of the forecast load growth is driven by growth in the LDC customer base. In northwestern Ontario the majority of the forecast load growth is driven by new or expanding large transmission-connected industrial customers, most of which are in the resource sector or are unique development projects. Therefore, when establishing the need for electricity enhancements and developing integrated alternatives, industrial customers generally drive the nature and magnitude of the electrical demand requirements.

The IRRP describes recommendations for system enhancements based on different scenarios, including staging options to mitigate reliability and cost risks related to demand forecast uncertainty associated with individual large customers. The recommendations in this report seek to ensure flexibility is maintained in order to accommodate changing long-term conditions.

In developing this IRRP, the Working Group followed a number of steps including: data gathering, including development of electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, preparation of a recommended plan including actions for the near and longer term. Throughout this process, engagement was carried out with local municipalities, First Nation communities, Métis community councils and local stakeholders. These steps are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



This IRRP documents the inputs, findings, and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation.

3.3 Greenstone-Marathon Sub-region Working Group and IRRP Development

The Working Group consists of representatives from the IESO, Hydro One Transmission, and Hydro One Distribution.

The IESO also met regularly with potential transmission-connected load and generating customers in the area and the IRRP was informed by these meetings. In particular, important information related to changes in electrical demand and generation production was provided by these potential customers.

3.4 Community and Stakeholder Engagement

Meaningful engagement with all communities in northwestern Ontario was an important element in developing this IRRP report. Early engagement meetings were held in October 2014 and were attended by a broad range of stakeholders and First Nation and Métis community members. In addition, the IESO attended meetings with municipalities, the Northwestern Ontario Municipal Association ("NOMA"), Common Voice Northwest ("CVNW"), and met with the board members of Waaskiinaysay Ziibi Inc. ("WZI") and a number of the Chiefs of the represented First Nations, and separately visited and met with Ojibways of Pic River First Nation and Pic Mobert First Nation, Constance Lake First Nation, Aroland First Nation, Ginoogaming First Nation, and Long Lake #58 First Nation. The IESO also met with the two Greenstone-Marathon Local Advisory Committees ("LAC"). Greater detail regarding community and stakeholder engagement activities is provided in Section 10 of this report.

4. Background and Study Scope

In 2014, the lead transmitter – Hydro One – initiated a Needs Screening process for the Northwest Ontario Region. The North of Dryden IRRP[5] and Remote Community Connection Plan[6] were already underway prior to the formalization of the regional planning process and were therefore not included within the scope of the Needs Screening process.

The Northwest Ontario Region Needs Screening study team determined that the need for coordinated regional planning had already been established and that a formal Needs Screening process was not required for the Northwest Ontario Region. A Scoping Assessment was then initiated.

4.1 Study Scope

On December 12, 2014, a draft Scoping Assessment Outcome Report ("Scoping Report") was posted for public comment. The Scoping Report[7] was finalized on January 28, 2015 incorporating feedback from communities, stakeholder, and First Nation and Métis community meetings.

The Scoping Report identified three new planning sub-regions for coordinated regional planning: Thunder Bay, West of Thunder Bay, and Greenstone-Marathon.

Regional planning initiatives in northwestern Ontario are illustrated in Figure 4-1.

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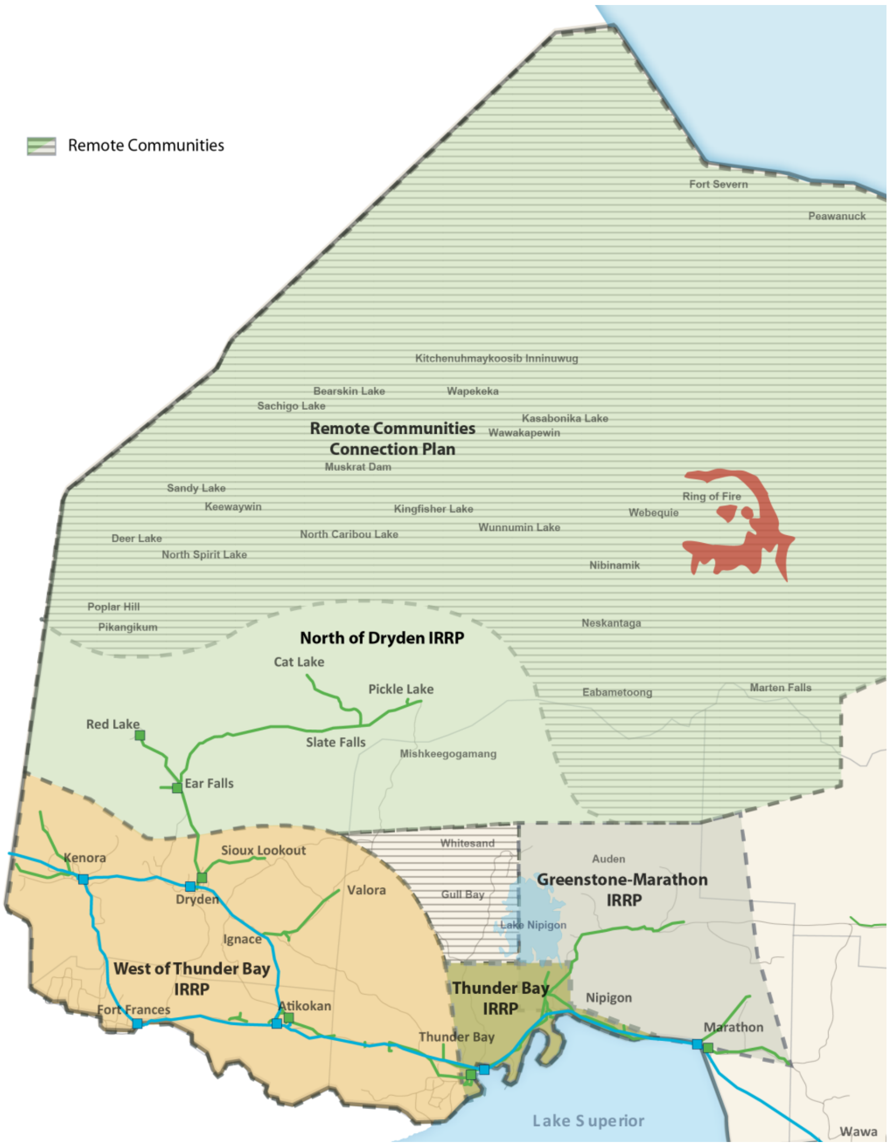
[5] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/North-of-Dryden.aspx

[6] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/Remote-Community-Connection-Plan.aspx

[7] http://www.ieso.ca/Documents/Regional - Planning/Northwest_Ontario/Final%20Northwest%20Scoping%20Process%20Outcome%20Report.pdf

Figure 4-1: Northwest Ontario Planning Region and Sub-regions



4.2 The Greenstone-Marathon Area Electricity System

Electricity is supplied to the Greenstone-Marathon Sub-region from two main sources: Marathon TS and Alexander SS. Marathon TS is located in the Town of Marathon and is a 230/115 kV station supplied at 230 kV from the East-West Tie which connects the northwest system near Thunder Bay and at Marathon to the northeast system at Wawa. At Marathon TS, power is then transformed from 230 kV to 115 kV for transmission customers. Alexander SS is located outside of the Township of Nipigon and is a large switching station where a number of hydroelectric generators south of Lake Nipigon - Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS - inject power into the system.

The Municipality of Greenstone and surrounding communities are supplied via a single-circuit 115 kV line (A4L) that connects from Alexander SS. Circuit A4L is approximately 150 km and generally follows the Highway 11 corridor. The natural gas-fired Nipigon GS, which holds a non-utility generator ("NUG") contract, is also connected to A4L.

The Town of Marathon and surrounding area is supplied via a single-circuit 115 kV line (M2W) that originates at Marathon TS and branches north to Manitouwadge and east to White River. Circuit M2W has a total distance of approximately 200 km. Hydroelectric generation at Umbata Falls GS and Wawatay Customer Generating Station ("CGS") also contributes to the electricity supply of the local area.

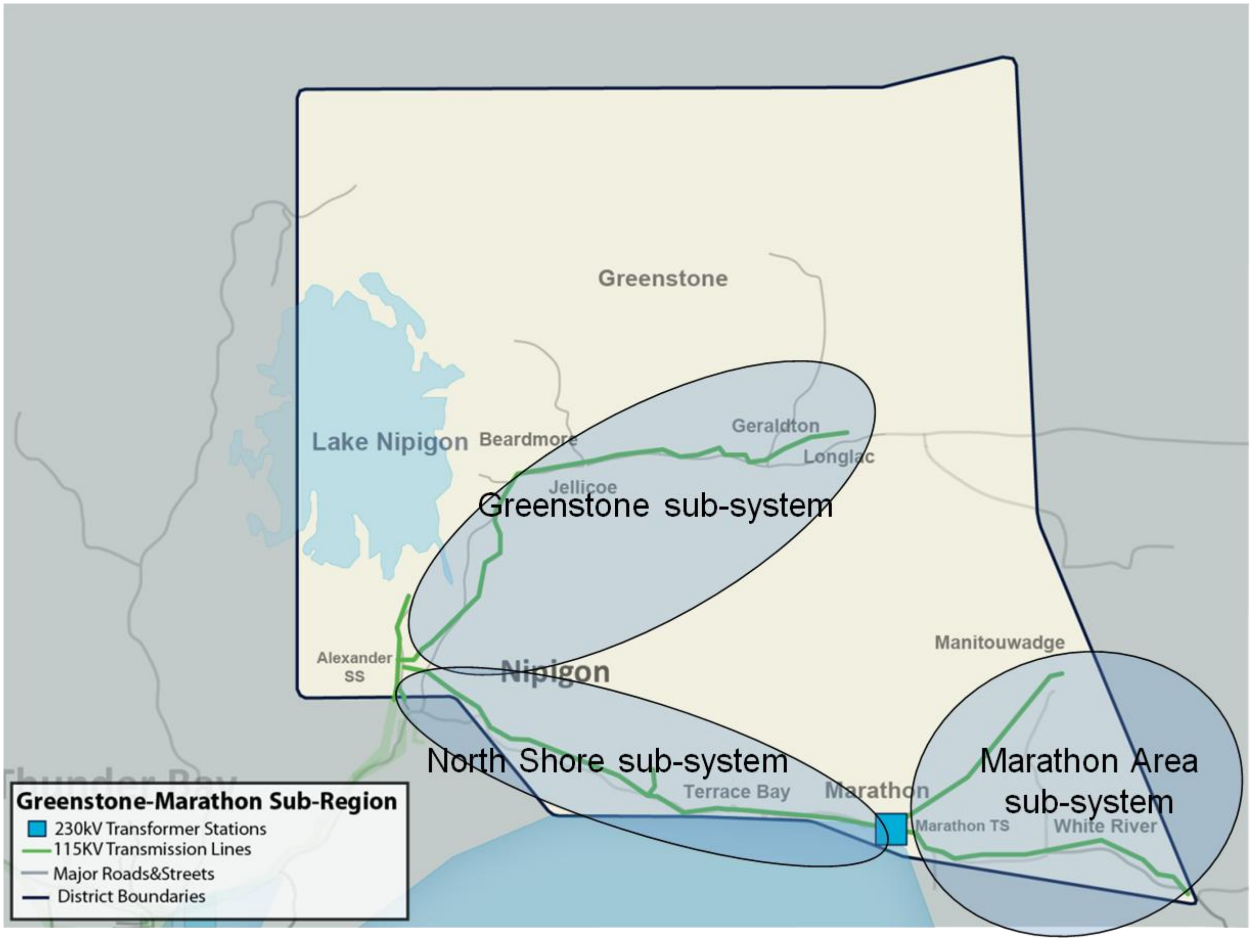
The communities along the north shore of Lake Superior between Nipigon and Marathon are supplied from three circuits in series (A5A / A1B / T1M) that terminate at Marathon TS and Alexander SS. The three circuits generally follow the Highway 17 corridor and have a total distance of approximately 170 km. Hydroelectric generation at Aguasabon GS is connected at Aguasabon SS, which is the terminus for circuits A5A and A1B, and also contributes to the supply of the local area.

4.3 Greenstone-Marathon Area Sub-systems

Within the Greenstone-Marathon Sub-region, there are three electrical sub-systems: Greenstone, North Shore, and Marathon Area.

The facilities supplying each sub-system are illustrated in Figure 4-2.

Figure 4-2: Greenstone-Marathon Sub-Region and Sub-systems



4.3.1 Greenstone Sub-system

The Greenstone sub-system is defined as being comprised of the existing and potential customers serviced from circuit A4L from Alexander SS to Longlac TS. Circuit A4L generally follows Highway 11 from Nipigon to Longlac. Circuit A4L serves the communities comprising the Municipality of Greenstone and serves as connection for Nipigon GS.

4.3.2 North Shore Sub-system

The North Shore sub-system is defined as being comprised of the existing and potential customers serviced from circuits A5A, A1B, and T1M, from Alexander SS to Marathon TS. Circuits A5A, A1B, and T1M are in series and generally follow the Highway 17 corridor. Together, these circuits interconnect Alexander SS to Marathon TS, however, each circuit comprises its own protection zone such that a fault on any one of the three circuits will not interrupt supply on the other two. Hydroelectric generation at Aguasabon GS is connected to the system at Aguasabon SS which is the interconnection between A5A and A1B.

4.3.3 Marathon Area Sub-system

The Marathon Area sub-system is defined as being comprised of the existing and potential customers serviced from circuit M2W, radial from Marathon TS to Manitouwadge TS and White River DS. Hydroelectric generation at Umbata Falls GS and Wawatay CGS is also connected to the system by circuit M2W.

5. Demand Forecast

5.1 Methodology for Establishing a Planning Forecast

The first step in developing an IRRP is establishing a planning forecast. A planning forecast is developed from a compilation of electrical demand data collected from LDCs and potential large customers connected directly to the transmission system. The effects of weather and coincidence factors are considered. Also, the demand reduction from CDM and DG are accounted for when developing the planning forecast.

As part of the lead transmitter's Needs Screening, LDCs are required to submit 10-year gross station demand forecasts. Consistent with the PPWG Report, LDC demand forecasts are further refined and a long-term (10-20 years) projection is also produced. Hydro One Distribution is the sole distributor in the Greenstone-Marathon Sub-region and it provided the Working Group with the gross station demand forecast and related assumptions. The effects of DG and expected conservation from LDC conservation targets were then applied.

The IESO regularly communicates with existing and potential transmission-connected industrial customers to ensure there is an understanding of their future electricity demand requirements. In the Greenstone-Marathon Sub-region, new industrial customers account for the majority of the forecast demand growth. However, the magnitude and timing of the electrical demand growth associated with large industrial customers, especially those in the natural resource sector (e.g., mining, oil, forestry) depend on a number of external factors such as the commodity price of the resource, the economic viability of the industrial project, and the ability to secure capital. In order to account for uncertainty of natural resource-based customers, the IESO developed multiple demand scenarios for potential and existing transmission-connected industrial customers by considering a number of factors, including:

- Customer plans
- 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)

Planning forecasts were developed based on LDC station demand forecast, the impact of CDM and DG, and the forecast scenarios of transmission-connected industrial customers.

5.2 Forecast Elements

The forecast developed for the Greenstone-Marathon IRRP includes quantitative and qualitative contributions from a number of parties including Hydro One Distribution, individual existing and potential industrial customers, local municipalities, First Nation communities and Métis community councils, industry associations, and interest groups.

5.2.1 Local Distribution Company Gross Demand Forecast

To support the regional planning process, the DSC requires that the LDCs provide gross station demand forecasts representing distribution customer demand projections. Hydro One Distribution has provided gross forecast projections for the step-down supply stations within the Greenstone-Marathon Sub-region indicated in Table 5-1 below.

Table 5-1: Step-down Stations by Sub-system

Beardmore DS #2	Marathon DS	Manitouwadge DS #1
Jellicoe DS #3	Schreiber Winnipeg DS	Manitouwadge TS
Longlac TS		Pic DS
		White River DS

LDC forecasts also include small industrial customers, such as saw mills connected to the distribution system. One notable inclusion is the re-start of two saw mills in the Municipality of Greenstone.

5.2.2 Conservation Assumed in the Forecast

In developing planning forecast scenarios, the Working Group also considered the extent to which planned CDM may impact peak demand.

In the report "Achieving Balance: Ontario's Long-Term Energy Plan" ("2013 LTEP"), the Ontario government established a provincial CDM target of 30 TWh in electricity reduction by 2032. To assist in achieving this target, the 2013 LTEP also committed to establishing a new 6-year Conservation First Framework beginning in January 2015. In order to represent the effect of provincial conservation targets within regional planning, the IESO developed an annual forecast for peak demand savings based on the provincial energy savings target which it expressed as a percentage of demand in each year. These percentages were apportioned to the

LDC demand forecast to develop an estimate of the peak demand impacts from the provincial targets in the Greenstone-Marathon Sub-region. The CDM targets included in developing the net demand forecast are provided in Table 5-2 below.

Table 5-2: Conservation Targets by Sub-system

Greenstone	0.1	0.4	1.4	2.2	2.5
North Shore	0.1	0.6	1.2	2.0	2.3
Marathon Area	0.2	1.0	1.9	3.0	3.5

5.2.3 Transmission Connected Customer Demand Forecast

The majority of forecast demand growth in the Greenstone-Marathon Sub-region is anticipated to be driven by potential large industrial customers that may connect directly to the transmission system. In the near term, potential industrial projects include a gold mine near Geraldton, and the pumping stations associated with a portion of a large gas to oil pipeline conversion project that generally follows the Highway 11 corridor. The life extension of an existing mine near Marathon, and a precious metals mine near Marathon are also considered.

In the medium and long term, a gold mine near Beardmore, and potential new supply to mining and remote communities in the Ring of Fire area using a North-South corridor are considered in the forecast scenarios.

5.3 Planning Forecast

To address peak electricity demand requirements for the sub-region, a scenario-based planning approach was used to account for uncertainty in demand forecast. As a result, the Greenstone-Marathon planning forecast consists of a number of scenarios which account for different possible industrial development outcomes. The scenarios all represent plausible outcomes that must be considered in planning for the electricity needs of the sub-region.

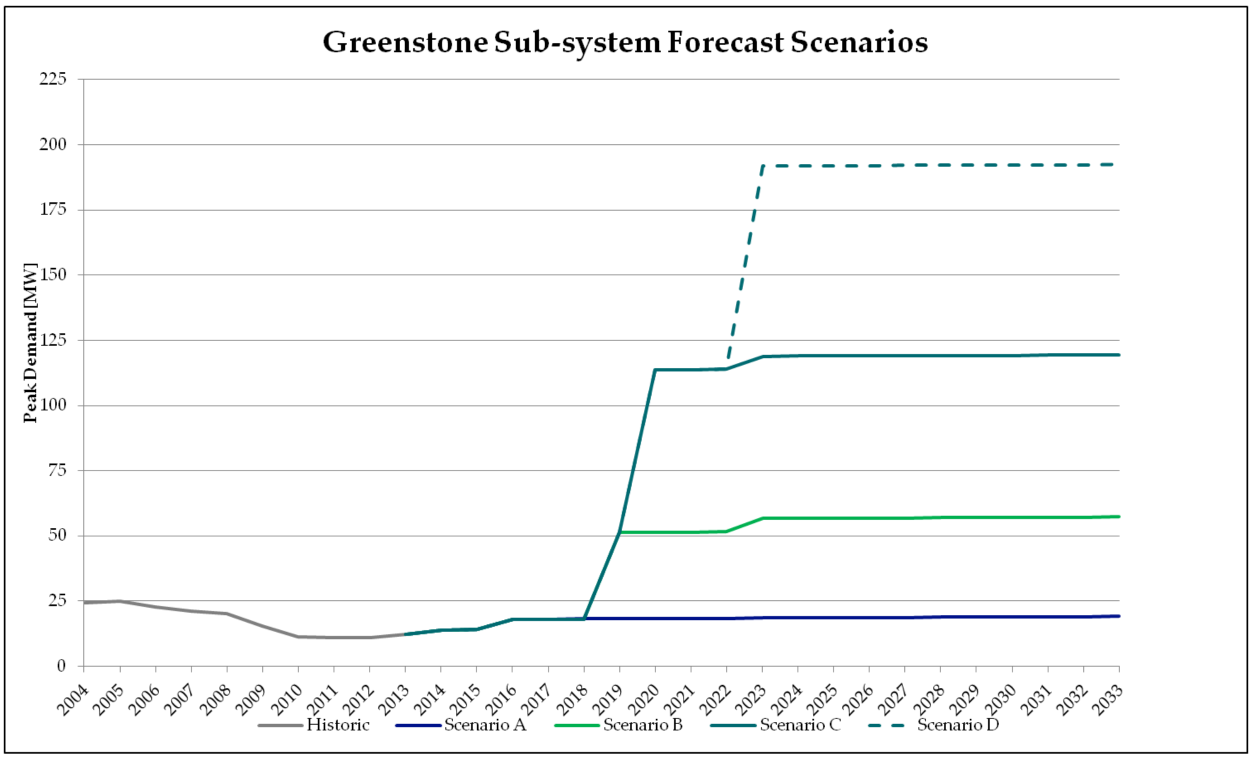
5.3.1 Greenstone Sub-system Forecast Scenarios

The following summarizes the forecast scenarios considered for the Greenstone sub-system. Since publishing of the Interim IRRP, scenarios have been updated to reflect the latest timelines and include medium and long-term developments, including the Beardmore mine and Ring of Fire.

Table 5-3: Greenstone Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth (including two saw mill re-starts)
B	Hydro One Distribution customer growth (including two saw mill re-starts), Geraldton mine materializes, and Beardmore mine materializes
C	Hydro One Distribution customer growth (including two saw mill re-starts), Geraldton mine materializes, Beardmore mine materializes and gas to oil pipeline conversion project materializes
D	Scenario C with the Ring of Fire area fully developed by 2023

Figure 5-1: Greenstone Sub-system Forecast Scenarios



Impacts to population and employment from potential industrial customers are considered in the respective scenario. It should be noted that the Greenstone sub-system forecast Scenarios B and C are equivalent until 2020, at which point they diverge. This is important when considering staging of options and will be discussed further in Section 7.2.2.

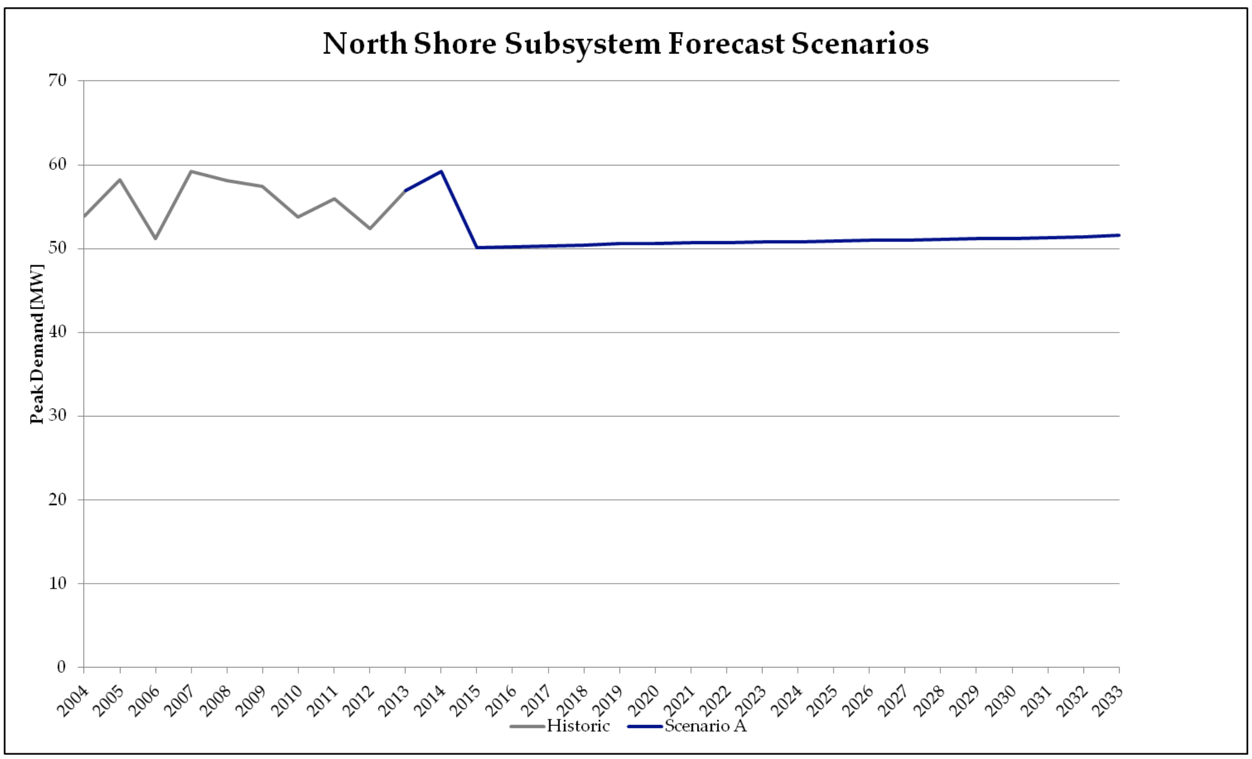
5.3.2 North Shore Sub-system Forecast Scenarios

Since the publishing of the Interim IRRP, the industrial customer is no longer considering behind-the-meter generation and so the accompanying scenarios that were included in the Interim IRRP have been removed from the IRRP analysis. Therefore, a single scenario is used for analysis in this IRRP for the North Shore sub-system and is summarized in Table 5-4 and Figure 5-2, below.

Table 5-4: North Shore Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth

Figure 5-2: North Shore Sub-system Forecast Scenarios



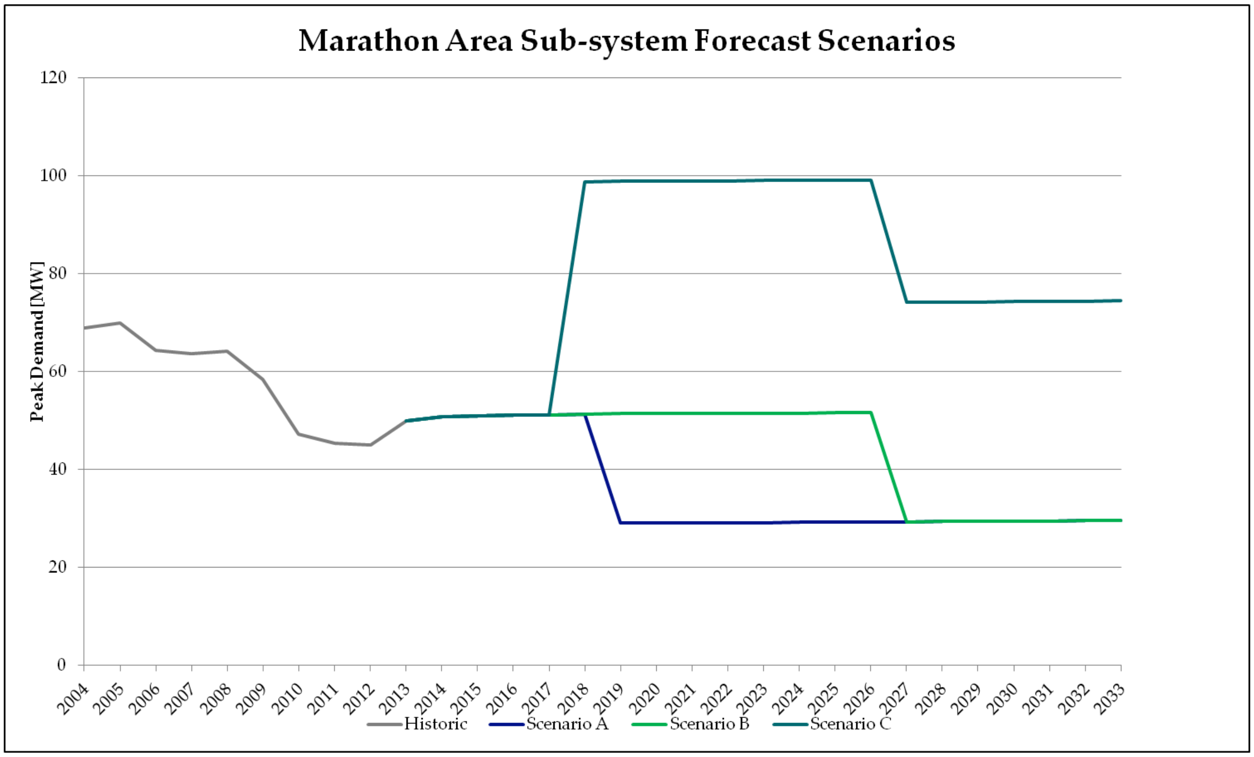
5.3.3 Marathon Area Sub-system Forecast Scenarios

The following summarizes the forecast scenarios considered for the Marathon Area sub-system, which have remained unchanged since the publishing of the Interim IRRP.

Table 5-5: Marathon Area Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth, no life extension of existing Marathon Area mine
B	Hydro One Distribution customer growth, with life extension of existing Marathon Area mine
C	Hydro One Distribution customer growth, with life extension of existing Marathon Area mine, and new Marathon Area precious metals mine materializes

Figure 5-3: Marathon Area Sub-system Forecast Scenarios



6. Electricity System Needs

For the purpose of this IRRP, the following section details the near-, medium-, and long-term needs established by the Working Group.

6.1 Methodology for Establishing Power System Needs

Once the planning forecast is developed, power system needs are established by determining the load meeting capability ("LMC") of the power system and determining if a shortfall exists between the electricity that can be supplied by the system in comparison to the forecast demand.

In order to determine the LMC of the power system supplying the Greenstone-Marathon Sub-region, Ontario and North American electricity planning standards are applied consisting of: the ORTAC, the Northeastern Power Coordinating Council ("NPCC") Directory #1 Standards, and the North American Electric Reliability Corporation ("NERC") Transmission Planning Standards ("TPL-001-4"). These documents outline power system planning and design standards and all are publically available.[8]

ORTAC represents the compilation of standards and best-practices in Ontario for long-term electricity plans, including IRRPs. ORTAC identifies certain system conditions, including contingencies, and the required level of performance under those conditions. The performance of the system is categorized based on equipment loading, voltage performance, load security and restoration (acceptable time periods for restoring customers after specified contingencies). Appendix A details the criteria applied in this IRRP.

The IESO recognizes that ORTAC, NERC, and NPCC planning criteria may not necessarily align with customer risk tolerances or their ability to pay for system reinforcement. Ultimately the decision of electric power supply resides with the benefitting customers so long as the reliability of the bulk system is not negatively impacted.

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[8] ORTAC: http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf
NPCC Directory #1:
https://www.npcc.org/Standards/Directories/Directory%201_Design%20Ops%20BPS%20clean%20GJD%2020150331_GJD.pdf
NERC TPL-001-4: http://www.nerc.com/files/TPL-001-4.pdf

6.2 Existing System Load Meeting Capability

In order to establish electricity supply requirements for the Greenstone-Marathon Sub-region, it is necessary to determine the LMC of each of the Greenstone, North Shore and Marathon Area sub-systems. The LMC of each sub-system is largely dependent on the connection point of the new customers forecast to connect. This is especially true in northwestern Ontario where the LMC of long circuits may be limited by voltage.

6.2.1 Greenstone Sub-system Load Meeting Capability

The Greenstone sub-system is limited by voltage for new customers near the Longlac area. The existing system, consisting of the A4L transmission line, has a total LMC of approximately 25 MW assuming the majority of load is concentrated in the Geraldton and Longlac areas near the end of the circuit. Based on demand forecast Scenario A, the Greenstone sub-system is not expected to be limiting, however all other scenarios are forecast to exceed the 25 MW limit in the near term. It should be noted that although circuit A4L is currently limited by voltage, it has a summer thermal rating of 260 A, or approximately 45 MW.[9]

6.2.2 North Shore Sub-system Load Meeting Capability

In addition to supplying customers, the North Shore sub-system also serves as the bulk system underlay for the East-West Tie. The North Shore sub-system can accommodate a total of approximately 100 MW of load and through-flow (from bulk transfers) during normal conditions. Flow along the North Shore sub-system is not expected to exceed 100 MW during normal conditions, even when the East-West Tie is loaded to its fair weather transfer limit and under a variety of local hydroelectric conditions.

Under the post-contingency condition where the double-circuit line M23L/M24L (which is a portion of the East-West Tie) between Marathon to Lakehead is lost, flows may exceed 100 MW along the North Shore sub-system during high transfer conditions. Overloading is mitigated and reliability is maintained by ensuring load is continuously supplied pre-contingency by the availability of the Northwest Remedial Action Scheme ("RAS"). Following the reinforcement of the East-West Tie between Wawa TS and Lakehead TS, currently planned to be in-service for 2020, reliability to the Northwest will be improved and the North Shore sub-system will also be

[9] In order to release the full thermal capability of facilities that are limited by voltage, reactive compensation of sufficient amounts to address the voltage limit would need to be installed. This is considered further in the Alternatives section of the report.

able to accommodate further growth. Therefore the North Shore sub-system is not expected to be limiting for new customers during this planning cycle.

6.2.3 Marathon Area Sub-system Load Meeting Capability

The Marathon Area sub-system is limited by voltage performance. Incremental reactive compensation may be required to connect additional customers. The further customers are from Marathon TS, the more reactive compensation will be required. The maximum load that the Marathon Area sub-system can accommodate based on the ORTAC load security limit for a single-circuit line is 150 MW. Based on existing forecasts, the Marathon Area sub-system is not expected to be limiting for new customers during this planning cycle.

6.3 Near-Term Needs

The near-term needs are described below by sub-system for each planning forecast scenario.

6.3.1 Near-Term Needs: Greenstone Sub-system

Capacity

The near-term capacity needs have been determined by comparing the near-term demand forecast, driven by the Geraldton mine and the gas to oil pipeline conversion project, to the LMC of the sub-system, and are tabulated below:

Table 6-1: Summary of Near-Term (present-5 years) Capacity Needs for the Greenstone Sub-system[10]

Demand Forecast [MW]	2015	2016	2017	2018	2019	2020
Scenario A	14	18	18	18	18	18
Scenario B	14	18	18	18	51	51
Scenario C	14	18	18	18	51	114
Greenstone LMC[11] [MW]	**25**					
Capacity Need [MW]						
Scenario A	0	0	0	0	0	0
Scenario B	0	0	0	0	26	26
Scenario C	0	0	0	0	26	89

[10] Scenario D is not considered for the near-term, as it is identical to Scenario C from 2015-2023

[11] Based on the capability of circuit A4L without any additional reactive compensation.

Power flow studies are included in Appendix B.

Load Security and Restoration

All demand forecast scenarios being considered up to 2020 remain less than 150 MW. This complies with the load security criteria outlined in ORTAC for a single-circuit line, which requires that no more than 150 MW be lost due to an outage on that line. Also, restoration from a normal outage should remain under eight hours, consistent with ORTAC.

Restoration from forced outages has generally performed within ORTAC. In the last five years, forced outages have been restored within eight hours with the exception of three sustained outages. These outages required crews to perform restoration work into the overnight period. The intent of the 8-hour criterion is that all non-catastrophic forced outages can be restored within a working day. Provisions exist in ORTAC to account for outages that take place outside of normal working hours and away from staffed centres; "approximate restoration times are intended for locations that are near staffed centres… [and] restoration times should be commensurate with travel times and accessibility"[12] (ORTAC 7.2). Therefore, no load security or restoration needs have been identified in the near term. A comprehensive reliability analysis is included in Appendix E.

Additional Customer Requirements

Fault analysis indicates that the available short-circuit at the end of circuit A4L is about 140 MVA[13] at the Longlac TS 115 kV bus. A potential mining customer near Geraldton has indicated that it requires at least 150 MVA available short circuit at 13.8 kV supply to ensure the functioning of its equipment. It has been estimated that the available short circuit would be about 105 MVA at 13.8 kV at the proposed Geraldton mine. Therefore, solutions for the area that consider the Geraldton mine scenarios must increase the available short circuit level, for example: through the use of generators, synchronous condensers or static synchronous compensators ("STATCOM"). Passive devices such as capacitors or Static Var Compensators ("SVCs") cannot provide the required short circuit level.

As well, for forecast scenarios that include the large gas to oil pipeline conversion project, the developer has informed the IESO that adjacent pumping stations cannot be lost for the same

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[12] ORTAC: http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

[13] Assuming the outage of Nipigon GS, representing a scenario that short-circuit availability is low

contingency. Therefore, provisions for appropriate supply diversity must be included for these relevant scenarios.

6.3.2 Near-Term Needs: North Shore Sub-system

The existing electrical system supplying the North Shore sub-system is expected to be sufficient for the planning horizon, given the latest information made available to the IESO. As indicated in Section 5.3, the North Shore sub-system is not forecast to experience net demand growth. Power flow study results are included in Appendix B for reference, and indicate that facilities are expected to perform within ratings with sufficient reliability.

6.3.3 Near-Term Needs: Marathon Area Sub-system

The existing electrical system supplying the Marathon Area sub-system is expected to be sufficient for the near-term.

This is also supported by the Stillwater Canada Inc. System Impact Assessment ("SIA") Report for the Marathon Platinum Group Metals (PGM) Copper Project, available on the IESO website.[14]

Power flow study results are included in Appendix B, and indicate that facilities are expected to perform within ratings with sufficient reliability.

6.4 Medium- and Long-Term Needs and Initiatives

The medium- and long-term needs for the Greenstone-Marathon Sub-region are discussed below in the context of four medium- and long-term initiatives including: additional mining claims in Greenstone, the possibility of an infrastructure corridor to the Ring of Fire, the Little Jackfish hydroelectric project, and community energy efficiency activities.

6.4.1 Additional Mining Claims in Greenstone

Other mining claims, beyond the Geraldton mine, exist along the Highway 11 corridor in the Greenstone area and additional local system reinforcement may be required if mines develop. Of particular interest is a potential gold mine near Beardmore that may be operational within the medium term. The mining developer's preliminary economic assessment results[15] indicate

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[14] http://www.ieso.ca/Documents/caa/CAA_2012-476_Final_Report.pdf
[15] http://www.premiergoldmines.com/i/pdf/2014-01-28_NR.pdf

that it would be economically advantageous for the Beardmore mine if processing and gold recovery were performed at the Geraldton mine.

Therefore, it has been assumed for purposes of this IRRP, that the Beardmore mine is included in scenarios that also include the Geraldton mine.

6.4.2 Infrastructure Corridor to the Ring of Fire

A North-South multi-use infrastructure corridor from near Nakina to the Ring of Fire continues to be a possibility for developers. As concluded in the 2015 North of Dryden IRRP, transmission supply for mining and remote communities is economic and the need for a new 230 kV transmission line to the Ring of Fire should be considered when developing an infrastructure corridor to the Ring of Fire. The 2015 North of Dryden IRRP also concluded that an East-West corridor from Pickle Lake or a North-South corridor from East of Nipigon or Marathon were comparable in cost if the Ring of Fire fully develops.

This IRRP report extends the analysis of a new 230 kV North-South transmission line to the Ring of Fire to consider the extent of possible economic efficiencies from multiple customers.

6.4.3 Little Jackfish Hydroelectric Project

The Little Jackfish hydroelectric project would require a new 180 km 230 kV connection line in order to provide power to the provincial electricity grid. The details of the connection line are included in Ontario Power Generation's ("OPG") project description[16] (pursuant to the Canadian Environmental Assessment Act).

The purpose of all IRRPs is to provide plans to reliably serve electricity demand, not to develop plans to connect system generation. However, potential transmission options exist that are detailed in Section 7 that may result in economic efficiencies for connecting the Little Jackfish hydroelectric project. Section 9.3 quantifies the economic efficiencies under the specific system expansion scenario that such efficiencies may result.

6.4.4 Community Energy Efficiency Activities

In a number of communities within the IRRP study area, electricity is the primary source for heating because there is no natural gas pipeline infrastructure. During municipal engagement

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[16] http://www.opg.com/generating-power/hydro/projects/little-jackfish/Documents/LJF_Project_Description.pdf

activities, the Town of Marathon communicated that electric heating has resulted in budgetary pressures and that the town is investigating the potential for cogeneration options. Section 9.4 provides a high-level avoided cost analysis for cogeneration. Similar solutions may also be a consideration for other communities without access to natural gas pipeline infrastructure. The IESO is including this planning-level economic analysis to provide communities with a methodology that they may use to determine planning-level feasibility.

7. Alternatives for Meeting Near-Term Needs

7.1 Methodology for Alternatives Development and Comparison

Once needs are identified, alternatives are developed that are technically feasible and are then compared on a relative basis against planning criteria. If a decision is required, given the forecast timing of needs and lead times for implementing feasible alternatives, a recommendation is made.

Alternatives may consist of one or a combination of CDM, generation, transmission, and/or distribution. Integrated alternatives that are capable of satisfying criteria for the forecast system condition and for the applicable scenario being assessed are then considered. Alternatives that are not capable of satisfying criteria are screened out and not considered further.

An economic analysis of the technically feasible alternatives is performed and the net present value ("NPV") of each option is determined based on the amortized costs that are incurred within a 20-year planning horizon.[17] The IESO used a real social discount rate of 4% in this analysis.[18] Generation and conservation options that contribute to provincial system supply needs are appropriately credited with the related economic benefit to ensure consistent comparison with all other options. Other factors such as environmental impact and social acceptance are considered, including information obtained from the engagement process. Detailed environmental impact analysis is performed by proponents during the implementation phase for projects requiring environmental assessment.

7.2 Alternatives Considered

7.2.1 Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioral changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

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[17] This is not the total project cost.

[18] The real social discount rate may be different than individual customer discount rates which account for the individual customer's own return on equity, risk, tax, etc.

However, within the Greenstone-Marathon Sub-region, the majority of the forecast load growth is anticipated to come from new industrial development, which is assumed to include relatively efficient equipment given the inherent economic benefits and latest codes and standards. Conservation expected to be achieved through provincial targets has already been included in the net demand forecast. Therefore, the potential for an additional amount of significant conservation that could address needs is limited.

Two of the available programs that transmission-connected industrial customers could be eligible for are the Industrial Conservation Initiative ("ICI") and the Industrial Accelerator program ("IAP"). The ICI encourages Class A customers to reduce their peak demand contributions, by providing a means to reduce their Global Adjustment charges.[19] IAP is geared to reducing electricity consumption on the provincial system, and to helping companies become more competitive by providing financial incentives that encourage investment in innovative process changes and equipment retrofits.[20] Opportunities for energy savings will continue to be explored for new and existing transmission-connected customers in the Greenstone-Marathon Sub-region.

7.2.2 Renewable Distributed Generation

A high level assessment of the cost of renewable DG resources to meet capacity needs in the Greenstone-Marathon Sub-region was conducted. This was performed by estimating a range of dependable capacity values for run-of-river hydroelectric, wind, and solar resources, based on median historical and simulated data for facilities in the Northwest Ontario Region. Dependable capacity refers to the portion of the total installed capacity that can be relied upon to meet local or system peak capacity needs. Consistent with ORTAC, this refers to the 98-percentile output of the resource. Based on the dependable capacity, unit costs were developed for these renewable resources. These unit costs are summarized in Table 7-1, below and range from $16 M/MW - $100 M/MW. Compared to the unit costs of detailed local generation and transmission options that are considered later in this report that range between $1.4 M/MW - $7.3 M/MW, renewable DG is not economic and can be screened out of further assessment.

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[19] More information on how Global Adjustment is calculated for Class A customers is available at http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx

[20] More information on IAP available: http://www.ieso.ca/Pages/Participate/Industrial-Accelerator-Program/default.aspx

Table 7-1: Summary of Analysis of Renewable DG

Resource Type	Dependable Capacity [%]	Unit Capacity Cost [M$/MW-dependable]	Levelized Unit Energy Cost [$/MWh]
Run of River Hydroelectric	15-30	16-66	60-110
Wind and Solar	5-28	7.5-100	80-400

It should be noted that storage systems may be effectively sized to increase the overall dependable capacity of an integrated renewable DG - storage system, though the unit costs of such system are expected to also increase due to the added battery systems. It is also expected that given the magnitude of the needs described in Section 6 of up to 89 MW of incremental LMC by 2020, and the dependability of the resources required, renewable DG options would be of impractical physical size. For example, a solar facility with a dependable capacity of 28% would need to be rated at approximately 320 MW to provide an LMC of 89 MW. Typical solar facilities can require over 5 acres of land per 1 MW.[21]

Although renewable DG is neither economic nor practical to meet the regional needs identified in the Greenstone-Marathon Sub-region, customers connected to the provincial power system have access to renewable energy programs which they may be eligible to participate. From a customer perspective, these programs may be effective in offsetting their individual electric utility costs. Ultimately, this is a customer decision that includes adherence to the corresponding program and connection availability rules.

7.2.3 Greenstone Sub-system Alternatives

The following sections describe the analysis of the different alternatives considered for each of the Greenstone sub-system forecast scenarios.

As indicated earlier, the Greenstone sub-system consists of one single-circuit 115 kV transmission line (A4L) with limited capacity and the near-term need for new capacity is driven by two specific industrial developments. Given that the options must account for a number of

[21] http://www.nrel.gov/docs/fy13osti/56290.pdf

factors such as the limitations of the existing system, the identified needs, and the staging of industrial customer electrical demand increases, a single transmission, generation, or DG alternative may not fulfill the range of customer requirements. In order to develop options that provide for the full scope of existing system limitations and customer capacity requirements, combinations of transmission, large generation, and DG facilities are considered. Off-grid alternatives are also considered for the purpose of cost comparisons. These alternatives include the following scenarios:

Table 7-2: Summary of Alternatives Considered for Scenarios

Scenario	Alternative	NPV Cost [M$]
A	"A0" – Continued sustainment of existing transmission system	0[22]
B	"B1" – Install reactive compensation and distributed generation	65
	"B2" – Install off-grid generation	190
	"B3" – Install reactive compensation and replace sections of circuit A4L	40
C	"C1" – Install reactive compensation, new 230 kV transmission supply and off-grid generation	170
	"C2" – Install reactive compensation, new 230 kV transmission supply and 115 kV connection line	160
	"C3" – Install new grid-connected gas generation and 115 kV connection line	340
	"C4" – Install off-grid generation	530

The result of the scenario-based alternative analysis is summarized below.

Scenario A does not result in the need for any new facilities. As a result, the continued sustainment of existing transmission infrastructure is adequate.

Analysis of Scenarios B and C indicates that a staged approach for recommended capacity enhancements best aligns with the timing of industrial developments. Stage 1 would economically maximize the existing system, while Stage 2 outlines the infrastructure expansion

[22] There is a cost of sustainment and maintenance programs. However, in the context of this option those costs would have been undertaken anyway as regular and good utility practice.

to accommodate a substantial increase in demand. Recommended Stage 1 and Stage 2 are summarized below.

Recommended Stage 1 – to accommodate the Geraldton mine
• Install +40 MVar of reactive compensation in the form of either a synchronous condenser or STATCOM at the Geraldton mine, to be in-service coincident with the mine • Install a customer-based grid-connected gas-fired generation plant of sufficient redundancy to meet the risk tolerance of the Geraldton mine [23]

In 2020, Scenarios B and C diverge. Scenario B includes only the demand from the Geraldton mine, whereas Scenario C includes both the mining demand and the demand from the gas to oil pipeline conversion project.

If, in addition to the Geraldton mine, the gas to oil pipeline conversion project proceeds and commits to electricity service according to schedule (2020), and consistent with Scenario C, the recommendation is:

Recommended Stage 2 – to accommodate the gas to oil pipeline conversion project
• Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac TS to be in-service coincident with the connection of the pumping stations loads • Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to connect the pumping station loads

If the gas to oil pipeline conversion project does not proceed or does not commit to grid supply, consistent with Scenario B, Stage 1 is sufficient to meet forecast demand. The following sections provide a detailed analysis of the alternatives listed in Table 7-2.

[23] The IESO has assumed N-1 reliability of the plant (single redundant unit), consistent with North American electricity reliability standards. If the generation can operate in island-mode, it may be advantageous to pursue this option due to the inherent supply diversity that it offers in comparison to replacing circuit sections of A4L (Option B3). The customer may also wish to investigate conservation incentives that the IESO offers, such as the ICI and IAP, to compliment this option.

7.2.3.1 Continued Sustainment of Existing System ("Option A0")

Under forecast Scenario A, no new industrial customers are supplied from the transmission grid. Under this scenario, the existing transmission system is sufficient to meet electrical capacity requirements in the Greenstone sub-system. No new facilities are required.

A comprehensive reliability analysis is included in Appendix E.

To maintain the reliability of circuit A4L, continued routine maintenance and sustainment activities consistent with Hydro One's maintenance practices and sustainment plans are expected to be adequate and meet planning criteria. Customers may choose to pursue further reliability investments independently.

7.2.3.2 Install Reactive Compensation and Distributed Generation ("Option B1")

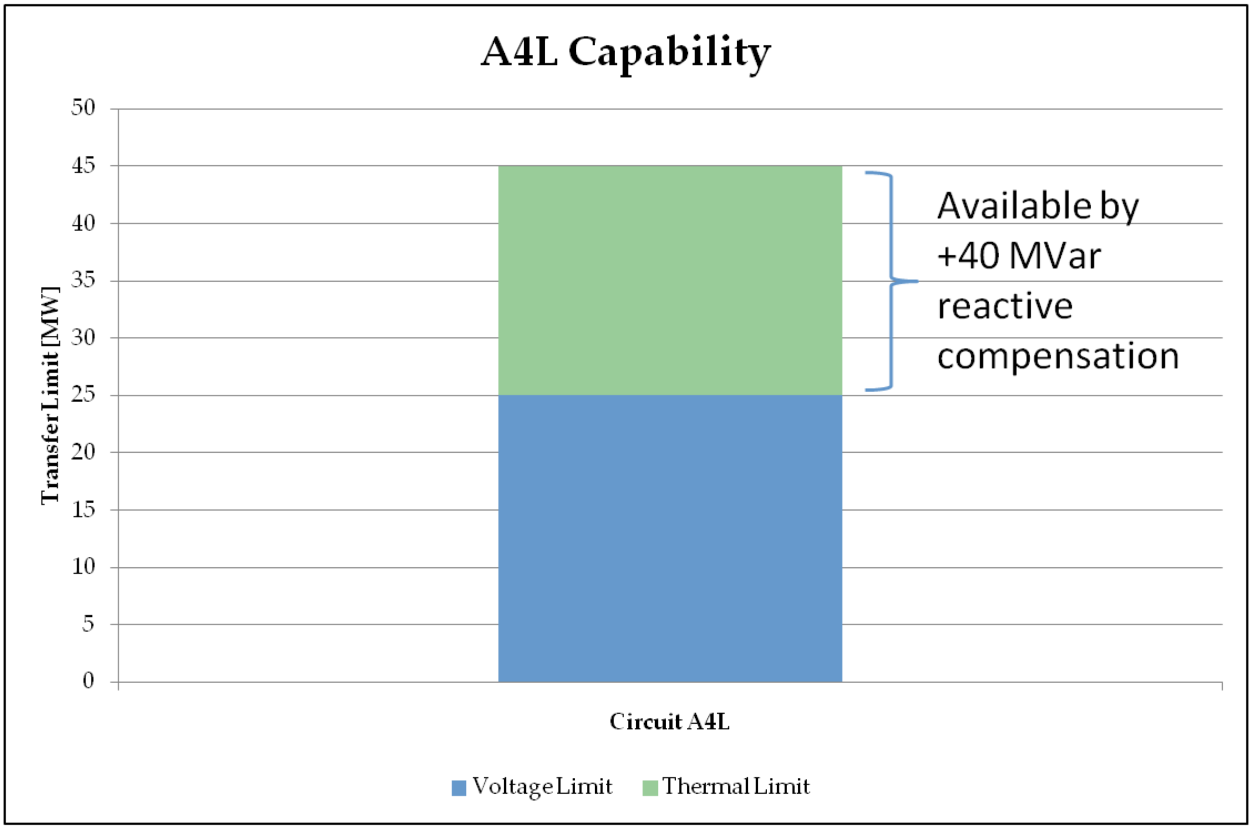
This option considers the needs based on load forecast Scenario B.

This alternative consists of installing additional reactive compensation totaling approximately +40 MVar in the form of either synchronous condenser(s) or STATCOM(s).[24] This would make available the full thermal capability of the circuit of 260 A, or approximately 45 MW (i.e. incremental LMC of 20 MW). As indicated in Section 6.3.1, considering motor starting requirements of the Geraldton mine, reactive compensation solutions would need to increase short circuit levels to 150 MVA at the mine site. Devices such as synchronous condensers or STATCOMs would be able to increase the available short circuit level, but passive devices such as capacitor banks or SVCs would not. This has been considered in the economic analysis by assuming the planning level capital cost estimate of the reactive compensation consistent with that of a synchronous condenser, which is approximately $7.5 million (or $5 M NPV).[25] It should be noted that STATCOMs are expected to be comparable in cost, based on information available to the IESO.

[24] In order to accommodate planned and unplanned outages, a RAS is also recommended.

[25] Estimate provided by Hydro One, based on information received from ABB.

Figure 7-1: Increase in A4L Capability with +40 MVar of Reactive Compensation



In order to accommodate the remaining capacity deficiency associated with the Geraldton mine, two 10 MW gas-fired generators may be installed.[26] For costing purposes, these generators are expected to produce about 43 GWh per year, which corresponds to the electricity that the mine is expected to require in excess of the 25 MW of capacity that may be grid-supplied.

A major benefit of using a combination of grid supply and local generation compared to Options B2 and B3 is the supply diversity. A contingency involving the grid or the on-site generators would still allow the mine to continue with some degree of production.[27] The customer may also wish to investigate conservation incentives that the IESO offers, such as the ICI and IAP, to complement this option and further reduce their costs.

[26] The IESO has assumed N-1 reliability of the plant (single redundant unit), consistent with North American electricity reliability standards.
[27] The level of supply security described for Option B1 would require that provisions are made such that the on-site generators being described can operate in island mode.

Power flow study results are included in Appendix C, and indicate that facilities are expected to perform within ratings with sufficient reliability.

The related economic analysis is included in Appendix D for reference.

The details of Option B1 are summarized below:

Table 7-3: Summary of Option B1

Option B1[28]	
Incremental Utilized Capacity [MW]	26
Undiscounted Capital Cost [M$]	65
Net Present Value Cost [M$]	65
Net Present Value Cost per Utilized Capacity [M$/MW]	2.5
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

7.2.3.3 Install Off-Grid Generation ("Option B2")

This option considers the needs based on load forecast Scenario B.

Circuit A4L, which serves the Greenstone sub-system, runs parallel to a portion of the TransCanada natural gas pipeline. A possible option is to continue to serve LDC demand with the existing electricity infrastructure, and for the Geraldton mine to supply their entire facility with on-site natural gas generation (i.e. not interconnected with the IESO-controlled grid). This option is included to provide existing and future customers with the full range of available options. It should be noted that the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid.[29]

[28] Using cost estimates for 9.5 MW gas engines as a representative cost.
[29] An exception is the December 16, 2013 ministerial directive which directed the former OPA to work with those remote First Nation communities where transmission connection is not economic and implement solutions for on-site renewable generation projects that reduce their dependency on diesel fuel and promote the use of renewable energy sources. http://www.powerauthority.on.ca/sites/default/files/news/December-16-2013-Directive-Renewable-Energy.pdf

The publically available draft EA Terms of Reference[30] for the Premier Gold Mines Ltd. Hardrock Mine indicates that 56 MW of generation capacity is anticipated to be required to meet demand with necessary redundancy.

For the purpose of the economic comparison, the installation of a 6x9.5 MW gas-fired engine power plant with dual-fuel capability is assumed. This arrangement would provide the required capacity indicated and account for N-2 redundancy, and address gas delivery risks. The on-site generation would produce approximately 260 GWh per year to supply the mine's energy needs.

The related economic analysis is included in Appendix D.

The details of the option are summarized below.

Table 7-4: Summary of Option B2

Option B2	
Installed Capacity [MW]	57 (6x9.5)
Incremental Utilized Capacity [MW]	26
Undiscounted Capital Cost [M$]	173
Net Present Value Cost [M$]	190
Net Present Value Cost per Utilized Capacity [M$/MW]	7.3
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

7.2.3.4 Install Reactive Compensation and Replace Sections of Circuit A4L ("Option B3")

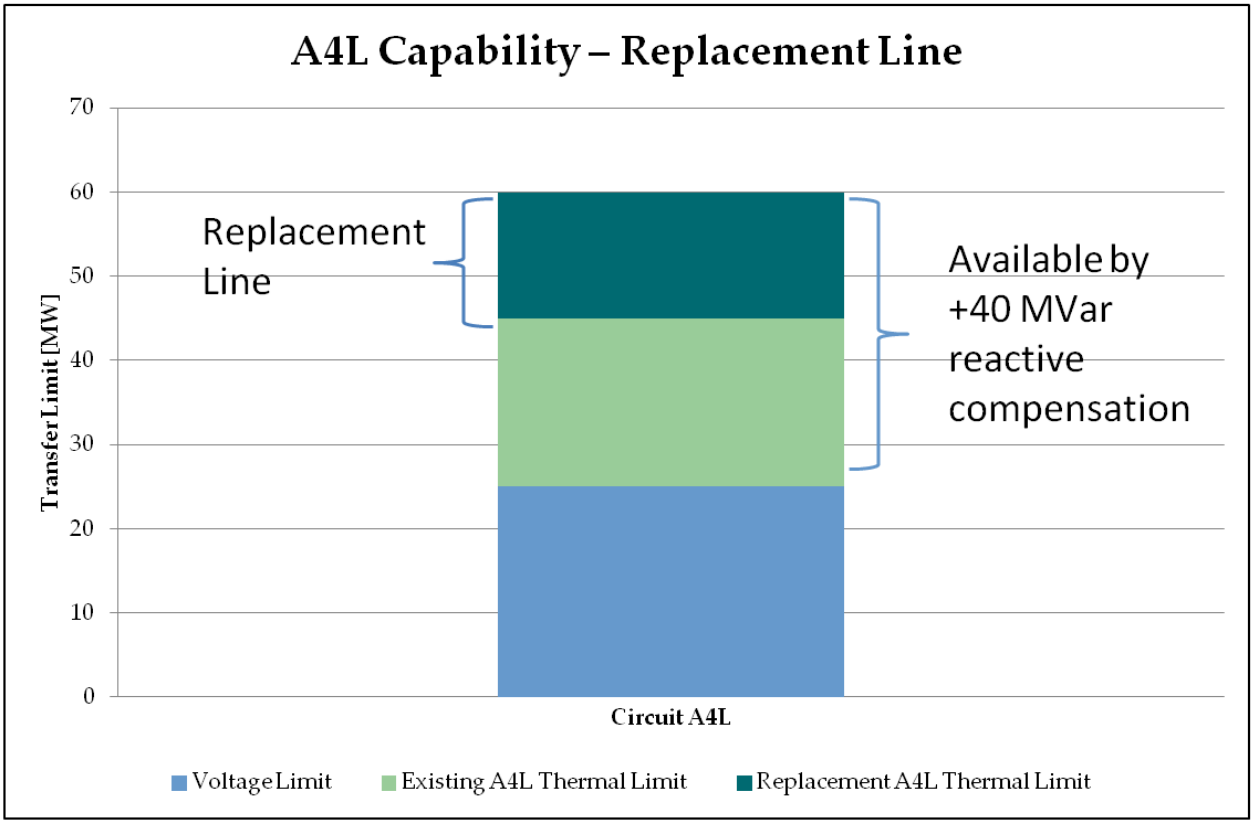
This option considers the needs based on load forecast Scenario B.

This option consists of installing additional reactive compensation of approximately +40 MVar in the form of either a synchronous condenser or STATCOM, and replacing the sections of circuit A4L between Nipigon and Longlac with a new 115 kV line using 477 kcmil Aluminum Conductor, Steel Reinforced ("ACSR") conductors. This would increase the ampacity of the

[30] http://www.premiergoldmines.com/i/pdf/HRTOR/EN/Main_ToR_fnl.pdf

circuit from 260 A to 310 A. If the circuit is fully compensated, this would increase the LMC to about 60 MW[31] which would accommodate the full 51 MW forecast for Scenario B.

Figure 7-2: Increase in A4L Capability with Nipigon to Longlac replaced with a new line equipped with 477 kcmil conductors and with +40 MVar of Reactive Compensation



This option would be optimally staged by first installing +40 MVar of compensation to provide an LMC of 45 MW to accommodate 25 MW of new demand. This would be followed by building the new line sections. The line sections may be constructed while the existing line serves customers, if right-of-way space is available. Otherwise, a bypass would be needed to allow for replacement of the existing line, which may increase costs by approximately 20%. Once the new line sections are constructed, existing facilities can be re-tapped on the new line sections. Following the installation of the new line sections, no additional reactive compensation

[31] The limiting section following the replacement of A4L between Nipigon Junction and Longlac is the section between Alexander SS and Nipigon Junction, which is 310 A. If this section was also replaced, the ampacity of the circuit could increase up to 620 A, which corresponds to an LMC of up to about 120 MW fully compensated. However, since forecast Scenario B only requires an LMC of 51 MW, upgrades were only considered from Longlac TS to Nipigon Junction and a full replacement of A4L was not considered further.

would be required to meet forecast demand beyond the +40 MVar as the larger conductors result in a reduced voltage drop across the line.

Power flow study results are included in Appendix C and indicate that facilities are expected to perform within ratings with sufficient reliability.

The related economic analysis is included in Appendix D.

The details of the option are summarized below.

Table 7-5: Summary of Option B3

Option B3	
Incremental Utilized Capacity [MW]	26
Undiscounted Capital Cost [M$]	62
Net Present Value Cost [M$]	40
Net Present Value Cost per Utilized Capacity [M$/MW]	1.4
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

The result of the analysis is that Options B1 and B3 (the grid-connected options) are comparable in cost based on the degree of accuracy of planning cost estimates, and are more economic than Option B2 (the off-grid generation option). Option B1 is recommended over Option B3 due to lead-time constraints. On-site compensation and gas-fired generation typically has a lead time of 1-2 years, while replacing a transmission line with a new line equipped with higher capacity conductors typically has a lead time of approximately five years due to required approvals, including Leave to Construct. However, if the in-service date of 2019 communicated to the IESO by the Geraldton mine developer is delayed, Option B3 is the most economic option and should therefore be pursued. Ultimately this decision rests with the Geraldton mine developer.

An additional consideration for the Geraldton mine developer is that the NPV cost of a new 230 kV line from the East-West Tie over the planning period, as recommended in Stage 2 to meet incremental demand in Scenario C, is approximately $70 million. The $70 million is comparable in cost to Option B1. Although a new 230 kV line may not be technically required immediately, and may require a similar lead time as Option B3 of five years, a new 230 kV source would provide greater reliability to the Geraldton mine customer and the existing

Greenstone customers. A new 230 kV line has been communicated by the LAC to be the preferred supply option by the local community. There may therefore be merit in the Geraldton mine developer pursuing a new 230 kV line immediately, considering the benefits of reliability and community support, while being mindful of the required lead times.

7.2.3.5 Install New 230 kV Transmission Supply to Longlac and Off-Grid Generation ("Option C1")

This option considers the needs based on load forecast Scenario C.

In order to accommodate an incremental capacity deficiency of about 60 MW, (associated with the Geraldton mine and connecting two large oil pumping stations that are located within the vicinity of the existing transmission system), an additional 230 kV supply would be required. The 230 kV supply option would consist of a new single-circuit 230 kV line, a new 230/115 kV auto-transformer located at or near Longlac TS, the associated protection and switching facilities, and reactive compensation (including +40 MVar of reactive compensation at the Geraldton mine consistent with Options B1 and B3). Detailed routing for the 230 kV line option can only be determined through an EA process. However, for planning purposes this report has considered two conceptual routing options for cost comparisons.[32] These two routing options are generally consistent with the routing options that have been communicated to the IESO by interested development groups and consist of an "East of Nipigon" route option, and a "West of Marathon" route option.

The East of Nipigon routing option is based on utilizing the existing Highway 11 corridor, generally running parallel with circuit A4L to Longlac TS and tapping M23L and/or M24L (the existing East-West Tie) between Marathon TS and Lakehead TS, near Nipigon. The length of the East of Nipigon route option would be approximately 150 km. The costing of this option considers single-circuit 230 kV H-frame wood poles with road access in northwestern Ontario.

The West of Marathon routing option is based on utilizing a least-distance, straight line route from the existing East-West Tie, tapping M23L and/or M24L west of Marathon, near Terrace Bay. The length of the West of Marathon route option would be approximately 100 km. The costing of this option considers single-circuit 230 kV H-frame wood poles without road access in northwestern Ontario (since it is considered to be on relatively undeveloped land).

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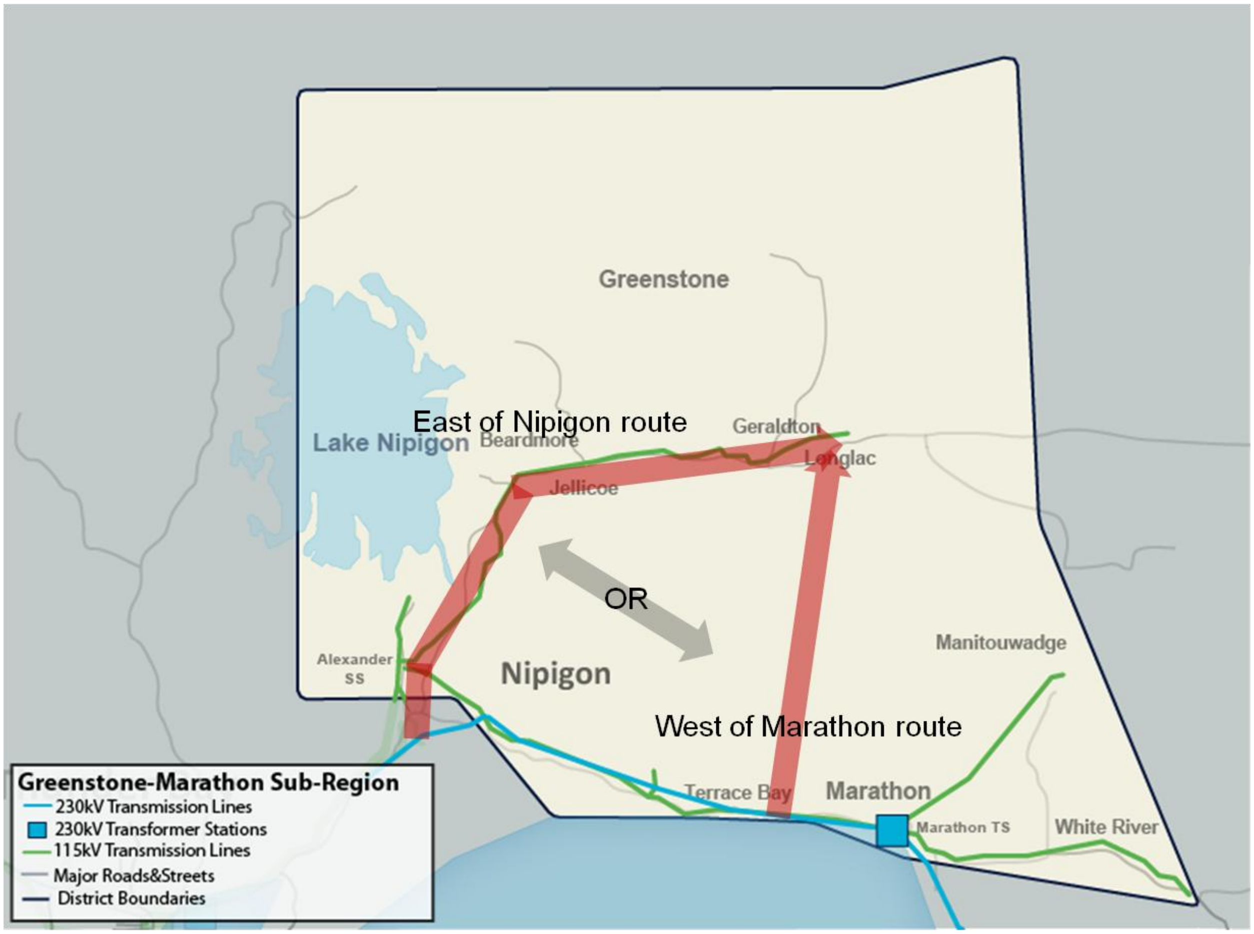
[32] A 230 kV transmission line routing other than the two concepts listed may be considered by proponents if the proposed arrangement provides equivalent or relatively better technical, economic, environmental, and social performance.

Figure 7-3: Option C1 illustrative[33] route map



The East of Nipigon route has the benefit of utilizing an existing corridor with highway access, and a lower per-distance cost (associated with road access), but is longer. The West of Marathon route option has the benefit of being more secure (since common mode failures of both A4L and a new line would be significantly reduced by a separate corridor) and is shorter. However, this option is more costly per-distance (since it has limited road access), and may have greater environmental impact. Details of environmental impacts would be considered during an EA process, where different routes would be considered by the project proponent.

Finally, the two pumping stations to the east of Longlac would be supplied from dedicated gas-fired generation (i.e. not interconnected with the IESO-controlled grid). This would account for the final approximately 30 MW (to total 89 MW) incremental capacity for this scenario. These

[33] The routes depicted are for illustrative purposes only and are not an indication of suggested routing for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

stations are geographically distant from the existing transmission system. As noted earlier, the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. This option is included to provide existing and future customers with a broader range of options for comparison.

Power flow study results are included in Appendix C.

The related economic analysis is included in Appendix D.

The details of Option C1 are summarized below:

Table 7-6: Summary of Option C1

Option C1	
East of Nipigon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	235
Net Present Value Cost [M$]	175
Net Present Value Cost per Utilized Capacity [M$/MW]	2.0
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes
West of Marathon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	225
Net Present Value Cost [M$]	170
Net Present Value Cost per Utilized Capacity [M$/MW]	1.9
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

Under this scenario, the N-1 load security would be 45 MW. This accounts for the loss of the new circuit. In considering the N-1 contingency scenario where the 230 kV line (option) is lost, the remaining system would consist of circuit A4L, which is all that exists today. Fully compensated, circuit A4L can accommodate 45 MW.

In order to remain within facility ratings, load would need to be reduced to 45 MW following the loss of the new circuit.[34] The resulting N-1 load security does not satisfy ORTAC requirements. Provisions exist in ORTAC to allow for a customer to agree to higher or lower levels of reliability, provided the bulk system is not negatively impacted. This provides flexibility to customers in the event that ORTAC required enhancements are not cost-effective for them.

Option C2 and Option C3 result in N-1 load security that is greater than Option C1 and satisfies ORTAC.

7.2.3.6 Install New 230 kV Transmission Supply to Longlac and New 115 kV Line from Longlac to Manitouwadge ("Option C2")

This option considers the needs based on load forecast Scenario C.

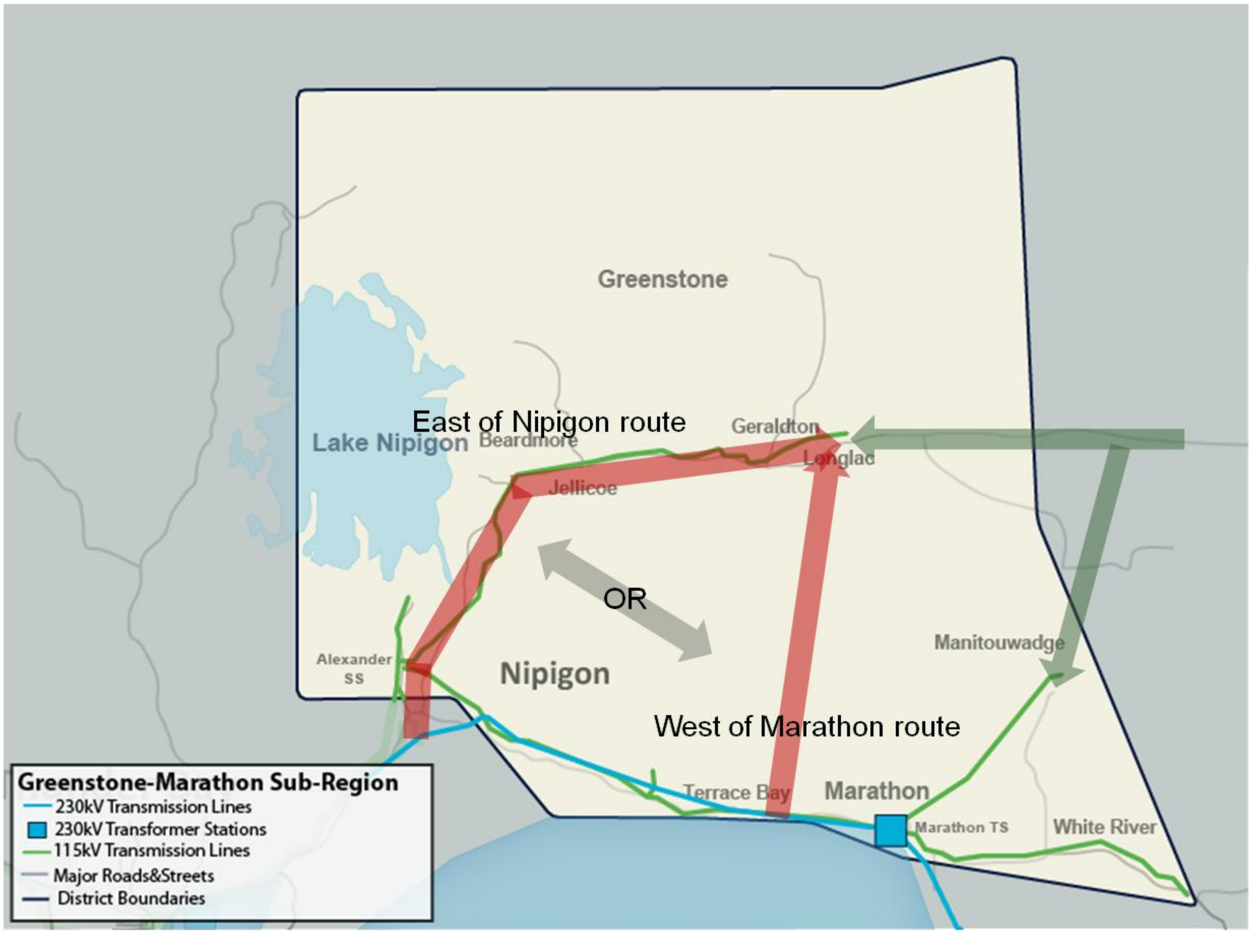
Option C2 builds on Option C1 and consists of installing a new 230 kV supply to the Greenstone area as well as installing reactive compensation (including +40 MVar reactive compensation at the Geraldton mine consistent with Option B1 and Option B3).

In addition, there are two pumping stations that are distant from the existing transmission system and would therefore require a new line if connection is preferred. This option considers installing a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS, as well as the associated protection, voltage control, and switching facilities.

This option also considers the re-termination of the Longlac TS load station on the 230 kV terminal, which would be installed to terminate the 230 kV line option. This is to reduce the overall risk of load loss by distributing load supply stations across different protection zones. The cost of the re-termination has been accounted for by including the cost of new step-down transformers.

[34] To reduce loading to 45 MW, considerations may be built into design configuration, or a Remedial Action Scheme may be installed.

Figure 7-4: Option C2 illustrative[35] route map



Installing switching facilities with appropriate redundancy to separately protect each pumping station can allow all four pumping stations in the area to be supplied from an expanded transmission system. The cost of this protection arrangement has been incorporated by including the cost of new in-line breaker facilities.

Power flow study results are included in Appendix C.

The related economic analysis is included in Appendix D.

The details of the option are summarized below:

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[35] The routes depicted are for illustrative purposes only and are not an indication of suggested routing for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

Table 7-7: Summary of Option C2

Option C2	
East of Nipigon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	270
Net Present Value Cost [M$]	160
Net Present Value Cost per Utilized Capacity [M$/MW]	1.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes
West of Marathon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	260
Net Present Value Cost [M$]	160
Net Present Value Cost per Utilized Capacity [M$/MW]	1.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

Option C2 would satisfy ORTAC and is comparable to the cost of Option C1 based on the degree of planning cost estimates.

7.2.3.7 Install New Generating Plant Near Longlac and New 115 kV Line from Longlac to Manitouwadge ("Option C3")

This option considers the needs based on load forecast Scenario C.

An alternative to Option C2, is to develop a generation-based option to provide a secure supply. Option C3 includes installing a new large grid-connected generation facility near Longlac TS, and building a new 115 kV single-circuit line to connect the two distant pumping stations. The generation plant would provide the required voltage support and short-circuit level to the area. Studies indicate that SVCs would still be required to address credible outage conditions, which have been factored into the costing of this option.

The available capacity of the generating plant would need to be 80 MW at a minimum to provide a secure supply under applicable criteria. For a natural gas-fired generation plant, this would correspond to the summer capability of the plant of 80 MW with at least one unit out of service, a substation with at least two step-up transformers, and a RAS to automatically shed load in the event of additional outage and/or contingency conditions. For the purpose of establishing planning level cost estimates, a 6x18 MW arrangement has been assumed. Other feasible arrangements may be considered.

This option is depicted in Figure 7-5 below.

Figure 7-5: Option C3 illustrative[36] route and generation map

The generating facility would need to be dispatched-on to at least minimum loading whenever the load in the area is expected to exceed 25 MW. The generation facility would also require an output level that ensures the local transmission facilities are able to respect N-1 conditions,

[36] The routes and generation sites are for illustrative purposes only and are not an indication of suggested routing/siting for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

which is limited by the 45 MW thermal capability of A4L. Based on the forecast energy profile of the area, the generation is expected to operate due to local constraints 100% of the time, and would need to produce on average approximately 85 GWh per year in 2019 and 425 GWh per year in 2020 and onward.

Power flow study results are included in Appendix C.

Related economic analysis is included in Appendix D.

Table 7-8: Summary of Option C3

Option C3	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	466
Net Present Value Cost [M$]	340
Net Present Value Cost per Utilized Capacity [M$/MW]	3.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

7.2.3.8 Install Off-Grid Generation ("Option C4")

This option considers the needs based on load forecast Scenario C.

Similar to Option B2, a possible option is to serve LDC demand with the existing electricity infrastructure, and for the Geraldton mine and the major pipeline project to supply their own facilities with on-site natural gas generation.

As indicated in Section 7.2.2.3, Option B2 would include provisions for 56 MW of power generation capacity at the Geraldton mine. Additionally this option would include provisions to supply each pumping station with on-site power generation that would not be interconnected with the IESO-controlled grid. For the purpose of establishing cost estimates, 9.5 MW units are assumed.

As noted earlier, the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. This option is included to provide existing and future customers with a broader range of options for comparison. Based on the average annual energy forecast for the Geraldton mine and the pumping stations, the energy production is expected to be approximately 260 GWh per year in 2019, and 555 GWh in 2020 and onward.

Table 7-9: Summary of Option C4

Option C4	
Installed Capacity [MW]	57 (6x9.5) + 76 (8x9.5)
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost	403
Net Present Value Cost [M$]	530
Net Present Value Cost per Utilized Capacity [M$/MW]	6.0
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

The result of the analysis is that Options C1 and C2 are more economic than Options C3 and C4. Option C2 is recommended based on economics and reliability. It should also be noted that given the recent timeline change for the Geraldton mine to a single stage in 2019, there may be economic merit in developing a new 230 kV line, consistent with Option C1 and Option C2, in advance of the pipeline project proceeding. This would result in avoiding some or all costs associated with the customer generation at the Geraldton mine described in Option B1 (section 7.2.2.2) for the years that a new 230 kV line may be advanced. Implementation will still require the necessary customer agreements to be in place to ensure the future transmitter can recover prudent costs.

7.3 Near-Term Plan Implementation Considerations

The near-term needs identified in the Greenstone area are driven by a few potential large industrial loads that may develop and choose to connect to the transmission system.

7.3.1 Implementation of Local Transmission Options

Local transmission serves the purpose of reliably supplying specific customer demand. Consistent with the current rules in the TSC, beneficiaries of transmission facilities must pay for the facilities. This is an established requirement and applies to all customers province-wide.

When developing new local transmission, as defined by the OEB, transmitters require financial commitment for capital recovery before incurring any costs associated with developing transmission. This commitment is usually in the form of an agreement between the transmission company and the customer. Customers are typically required to commit to a Connection Cost Recovery Agreement ("CCRA") with the transmitter before the transmitter commits investments for development work. This report therefore does not provide any implementation authority, but simply documents the Working Group's assessment of need and options available for these customers.

Note, on January 11, 2016 the OEB issued a letter stating that it will be holding a Regional Planning and Cost Allocation Review (EB-2016-0003) aimed at ensuring that cost responsibility provisions for load customers under the TSC and DSC are aligned to facilitate regional planning and implementation of regional infrastructure plans. This process may result in changes to the current cost allocation rules contained in the TSC and DSC.

7.3.2 Implementation of Grid-Connected Generation Options

The IESO procures generation resources when needed to supply the Ontario system demand. When doing so, the IESO seeks to minimize marginal energy costs for all Ontario ratepayers. In considering local generation options, the IESO takes into account system needs, feedback from the local community, whether the lowest marginal cost resource can be sited in that local area and whether that option could defer or completely address local needs.

The IESO does not generally procure new generation resources to supply a set of customers in a particular local area if there is no need for system generation, or if that local generation option results in a relatively higher marginal cost compared to other available generation options. If the benefitting customers wish to establish a capacity and energy agreement directly with a local merchant generation company for grid-connected generation, as opposed to other potential supply options (e.g., local transmission or off-grid generation), then they may do so. The local merchant generator would still be subject to all the requirements to connect to the IESO-controlled grid.

The onus is on the customer to engage the electricity service provider that meets its needs. This report therefore does not provide any implementation authority, but simply documents the Working Group's assessment of need and options available for these customers.

7.3.3 Implementation of Off-Grid Generation Options

The IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. Therefore, it is the responsibility of the customer to develop these options.

To inform customers and local communities of the technical viability and expected costs, some off-grid generation options have been developed for the purpose of illustrating a planning-level cost comparison with grid-connected options.

8. Recommended Near-Term Plan

The following elements of the Greenstone-Marathon IRRP are recommended for near-term development to address demand forecast Scenarios A, B, or C. These scenarios are based on the Working Group's understanding of the various long-term opportunities, and on feedback from the community.

Since publishing the Interim IRRP in June, 2015, the Geraldton mine developers notified the IESO of adjustments to their project schedule and scope. Specifically, they now expect to connect in a single stage in 2019, as opposed to two stages in 2018 and 2020 (which was considered in the Interim IRRP[37]). The IESO's recommendations have been revised accordingly.

The IESO recommends a staged approach to accommodate forecast demand from the Geraldton mine and the pumping stations from the gas to oil pipeline conversion project.

Demand Scenario A

The existing system is sufficient to meet the demand requirements presented in Scenario A. To maintain the reliability of circuit A4L, continued routine maintenance and sustainment activities consistent with Hydro One's maintenance practices and sustainment plans are expected to be adequate and meet planning criteria.

Demand Scenario B

Demand requirements for Scenario B considers the Geraldton mine proceeding in 2019. The Working Group therefore recommends the following to address Stage 1 requirements for Scenario B:

Recommended Stage 1 – to accommodate the Geraldton mine
• Install +40 MVar of reactive compensation in the form of either a synchronous condenser or STATCOM at the Geraldton mine, to be in-service coincident with the mine • Install a customer-based grid-connected gas-fired generation plant of sufficient redundancy to meet the risk tolerance of the Geraldton mine.

[37] http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Greenstone_Marathon/Greenstone-Marathon-Interim-IRRP-Report-only-Final-20150622.pdf

Figure 8-1: Recommended Near-Term Plan: Stage 1

By initially installing reactive compensation, this maximizes the use of the existing system. The associated NPV cost of +40 MVar of compensation is estimated at approximately $5 million.

Incremental electrical demand needs would be met by customer-based generation. The associated NPV cost of this generation is estimated at approximately $60 million.

The recommendation for customer-based grid-connected gas generation is due to the lead-time requirements communicated to the IESO by the Geraldton mine developer of 2019. However, it should be noted that if the in-service date of 2019 is delayed, Option B3 – upgrading of circuit A4L – is the most economic option under Scenario B and should therefore be pursued. Ultimately this decision rests with the Geraldton mine developer.

Demand Scenario C

If, in addition to the Geraldton mine, the gas to oil pipeline conversion project proceeds and commits to electricity service, and consistent with Scenario C, the Working Group recommends:

Recommended Stage 2 – to accommodate the gas to oil pipeline conversion project
• Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac TS to be in-service coincident with the connection of the pumping stations loads • Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to connect the pumping station loads

Figure 8-2: Recommended Near-Term Plan: Stage 2

Under Scenario C, a new 230 kV transmission supply to Longlac is the most economic option. The associated NPV cost of a new 230 kV supply to the area including associated line, transformation, switching, and terminations is estimated at approximately $70 million.

This option maintains long-term flexibility for a North-South corridor to the Ring of Fire. From a long-term perspective, it is advantageous to develop a transmission supply to Longlac, rather than installing large grid-connected generation. This is because in order to develop a new North-South transmission supply to the Ring of Fire, a 230 kV line to Longlac would be required, and therefore developing large generation would represent an added cost. A North-South corridor option to the Ring of Fire is discussed further in section 9.2.

Should the pipeline developer decide to connect all pumping station loads in the Greenstone-Marathon Sub-region to the transmission system with N-1 supply security, it is recommended that a new 115 kV transmission line linking Longlac TS and Manitouwadge TS be developed. The associated NPV cost of the new 115 kV single-circuit line, compensation, in-line breaker stations and switching facilities is estimated at approximately $90 million.

The total NPV cost of Stage 2 is estimated at approximately $160 million.

It should also be noted that given the recent timeline change for the Geraldton mine, now planned as a single stage in 2019, there may be economic merit for the Geraldton mine in the development of a new 230 kV line in advance of the pipeline project proceeding. This would result in avoiding some or all costs associated with the customer generation at the Geraldton mine described in Stage 1 for the years that a new 230 kV line may be advanced. Implementation would still require the necessary customer agreements to be in place to ensure the future transmitter can recover prudent costs.

9. Options for Meeting Medium- and Long-Term Needs

This section describes approaches, alternatives, and recommendations for the medium- and long-term planning periods. Specific options and initiatives are described in detail related to the medium- and long-term as indicated in Section 6.4 and include: additional mining claims in Greenstone, infrastructure to the Ring of Fire, Little Jackfish hydroelectric project, and community energy efficiency initiatives. Recommended actions and implementation considerations for the medium- and long-term plan are discussed.

The specific alternatives considered for the medium and long term depend on the level of growth that materializes in the near term, as well as the extent to which the local electricity system is reinforced in the near term to accommodate that growth. The specific scenarios being considered are described below for the respective medium and long-term initiatives.

9.1 Additional Mining Claims in Greenstone

A number of mining claims exist along the Highway 11 corridor in the Greenstone area. Of particular interest is a potential gold mine near Beardmore that may be operational in the medium term. As indicated in the Beardmore mine developer's preliminary economic assessment results[38], it would be economically advantageous for the Beardmore mine if processing and gold recovery were performed at the Geraldton mine.

Therefore, for planning purposes, it has been assumed that the Beardmore mine is included in Geraldton mine scenarios. The Geraldton mine is considered in all scenarios except Scenario A.

The recommended near-term plan to meet forecast demand outlined in Scenario C consists of Stage 1 and Stage 2. If Stage 1 and Stage 2 are implemented by the respective developers and service providers, then sufficient capacity would be available to accommodate the Beardmore mine. Power flow analysis is included in Appendix F.

If the Geraldton mine and the major gas to oil pipeline conversion project proponents decide to pursue off-grid options, which are not recommended by the Working Group, then the existing system would have sufficient margin to accommodate the Beardmore mine.

The recommended near-term plan to meet forecast demand outlined in Scenario B consists of only Stage 1. If Stage 1 is implemented by the respective developers and service providers, then

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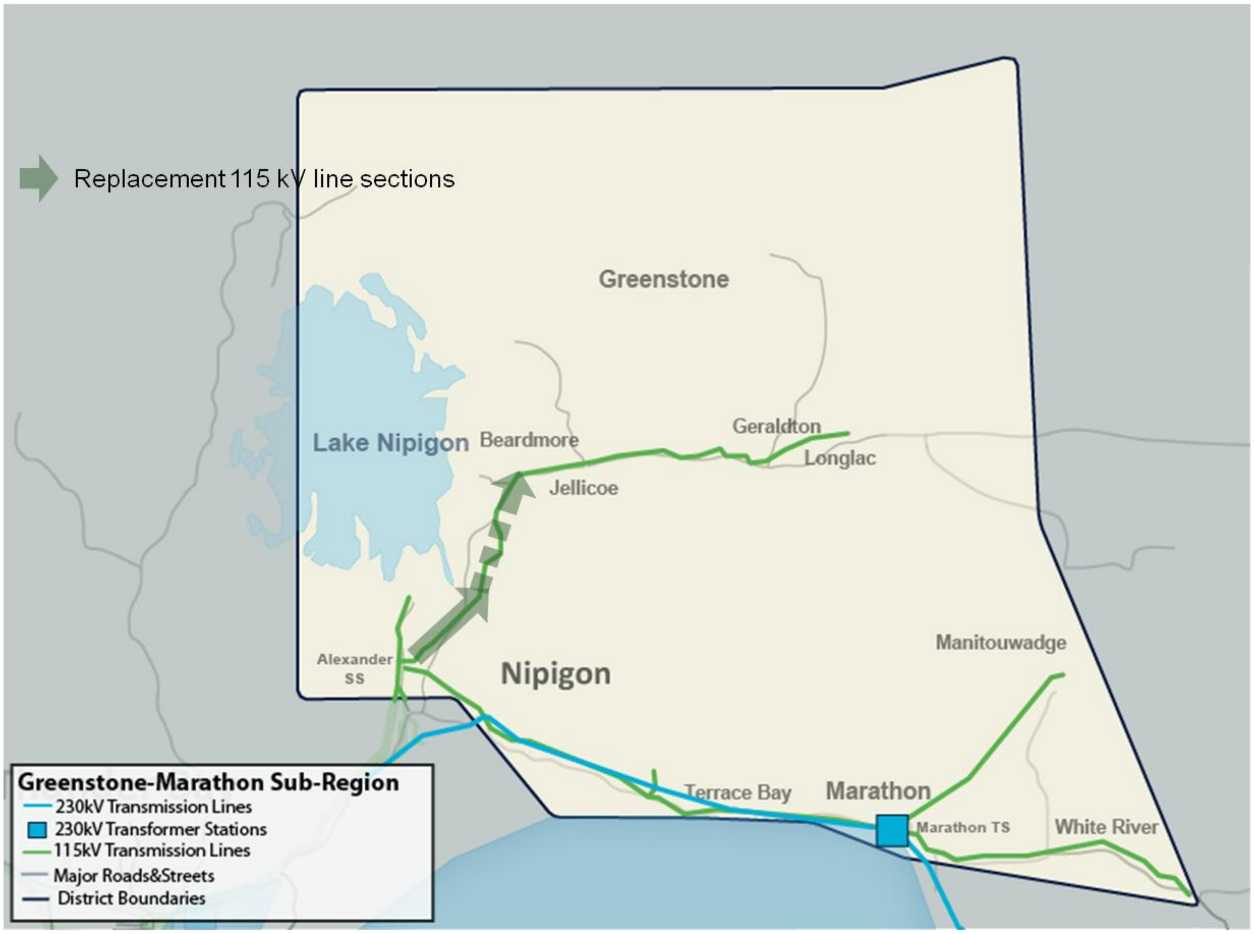
[38] http://www.premiergoldmines.com/i/pdf/2014-01-28_NR.pdf

additional capacity enhancements would be required to accommodate additional customer demand. Power flow analysis is included in Appendix F, which illustrates the need for additional enhancements. Therefore, this analysis of additional mining is focused on Scenario B. As indicated in sections 9.1.1 and 9.1.2, transmission upgrade options and new or expanded local generation options are available. Analysis indicates that the transmission upgrade options available are more economic than generation options to supply the Beardmore mine under Scenario B.

9.1.1 Transmission Upgrade

Incremental capacity to accommodate additional mining development may be in the form of transmission system enhancements to deliver power to the Beardmore mine customer. This would be economically achieved by upgrading or replacing sections of circuit A4L from Alexander SS to the Beardmore mine. If this option is combined with replacing A4L from Nipigon Junction to Longlac TS in Option B3 (i.e. replacement of all of A4L), then the Greenstone sub-system would be capable of supporting up to approximately 120 MW, fully compensated.

Figure 9-1: Transmission Upgrade Option for Additional Mining in Greenstone



It has been estimated that the NPV cost associated with this option is $10-15 M.[39]

9.1.2 Local Generation

Incremental capacity to accommodate additional mining development may be in the form of new or expanded local generation resources. Two possible generation options to provide capacity to supply the demand from the Beardmore mine have been considered: a new 2x10 MW gas generating facility near Beardmore, or 1x10 MW expansion of a gas generating facility in Geraldton (considered if 2x10 MW gas generating plant is implemented for Stage 1).

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[39] The cost associated with this option depends on the decision by the customer. If this option is combined with replacing A4L from Nipigon Junction to Longlac TS as in Option B3, then only the sections from Alexander SS to Nipigon Junction of 35 km need to be upgraded ($8 M NPV), as opposed to from Alexander SS to Beardmore TS of 65 km ($15 M NPV).

Figure 9-2: Local Generation Option for Additional Mining in Greenstone

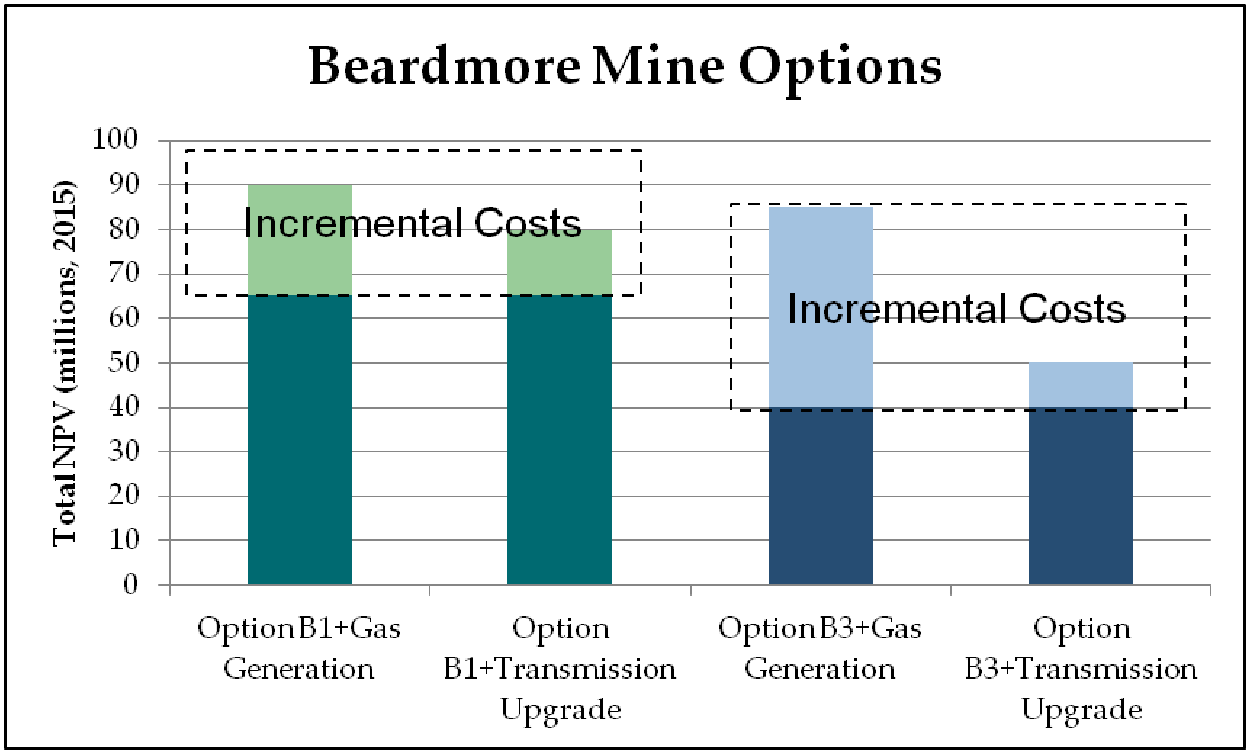
It has been estimated that the NPV cost associated with this option is $25-45 M.[40]

9.1.3 Comparison of Options

As indicated, depending on the solution selected for supplying the Geraldton mine, different incremental costs may result. This is illustrated in Figure 9-3 below.

[40] The cost associated with this option depends on the decision by the customer. If this option is combined with a 2x10 MW gas generating plant at the Geraldton mine as in Option B1, the facility could be expanded by one gas genset ($25 M NPV), as opposed to the installation of a separate facility with at least two gas gensets ($45 M NPV).

Figure 9-3: Comparison of Options for Additional Mining in Greenstone



9.2 Infrastructure Corridor to the Ring of Fire

The 2015 North of Dryden IRRP included an analysis that considered the supply to the Ring of Fire. This analysis included a planning-level cost-comparison between the following options: mine self-generation and separately connect remote communities, an East-West transmission corridor from Pickle Lake, and a North-South transmission corridor from either east of Nipigon or Marathon.

The analysis contained in this report expands the work completed as part of the 2015 North of Dryden IRRP to consider potential cost savings by the potential customers in the Ring of Fire area and Greenstone-Marathon Sub-region. This analysis is based on typical cost allocation principles consistent with the TSC, namely that capital contribution is generally determined based on the relative proportions of non-coincident peak demand of individual customers to that of other customers benefitting from the facility.[41]

[41] Ultimately cost allocation is determined by the OEB. This report simply presents a reasonable assumption to illustrate the potential for cost savings and communicate that it is advantageous for multiple customers to share the utilization of new facilities.

The greatest potential cost savings to benefitting customers results when the new infrastructure is highly utilized by a large number of customers. This is consistent with the following scenario illustrated in Table 9-1.

Table 9-1: Scenario Assumed for Ring of Fire Cost Sharing Evaluation

Timing	New Customers	Infrastructure
Near Term (0-5 years)	Geraldton mine, gas to oil pipeline conversion project	Recommended Stage 1 and Stage 2
Medium and Long Term (5-20 years)	Beardmore mine, Ring of Fire mines and remote communities	North-South transmission line to Ring of Fire

Table 9-1 describes the forecast Scenario D presented in section 5.3.1. It is important to note that Recommended Stage 2 consists of a new 230 kV transmission line from the East-West Tie to Longlac TS. This facility could also serve as the southern sections of a new North-South transmission line to the Ring of Fire, if that option is pursued. Therefore, it would be reasonable to suggest that all new customers under this scenario would contribute to the 230 kV transmission line from the East-West Tie to Longlac TS (southern section), as per recommended Stage 2. This greater utilization and cost-sharing could reduce costs for all new customers in the area.

The remaining northern sections of a new North-South transmission line from Longlac TS to the Ring of Fire would only serve customers in the Ring of Fire area, and no additional cost-sharing is expected.

Table 9-2: Relative Utilization of a 230 kV Line to Supply Greenstone and the Ring of Fire

Customer Group	New Customer Peak Demand	230 kV Line – Southern Section Utilization	230 kV Line – Northern Section Utilization
All	170 MW	170 MW	75 MW
Greenstone sub-system	95 MW	56%	0%
Ring of Fire sub-system	75 MW	44%	100%

Table 9-2 indicates that a significant potential for cost-sharing could result for all new customers from shared utilization of a 230 kV transmission line being recommended as part of Stage 2 (referred to as 230 kV line – southern section in Table 9-2).

9.3 Little Jackfish Hydroelectric Project

Similar to the potential cost savings outlined in the previous section related to the Ring of Fire, recommended Stage 2 could also result in some connection cost savings to the Little Jackfish hydroelectric project. Although analysis of individual generation projects is not within the typical scope of IRRPs, following discussion with the proponents it was agreed that assessing the potential connection cost savings would be valuable information.

The 230 kV transmission line recommended as part of Stage 2 could utilize the East of Nipigon route option, as described in sections 7.2.3.5 and 7.2.3.6. Most notably, the southern routing of this option from the East-West Tie to near Beardmore is largely consistent with the southern routing of the 230 kV connection line routing that OPG considered as part of the EA for the project. This section of the East of Nipigon 230 kV line route option as part of recommended Stage 2 would result in a reduction in the length of the connection line for the Little Jackfish project by approximately one half. During earlier economic evaluations of Little Jackfish, it was believed that the cost of the connection line significantly impacted its viability. The IESO has included updated economic analysis based on the possible development of a new East of Nipigon 230 kV line.

This results in a reduction in the connection line cost by about half and a reduction in the Levelized Unit Energy Cost ("LUEC") from $150/MWh to $144/MWh, or about a four percent reduction. With the reduced LUEC, the Little Jackfish project is $50- $80/MWh[42] more than the cost of system supply. Additional details are included in Appendix H.

Therefore, further analysis has found that the potential reduction in connection cost for the Little Jackfish project does not result in a significant reduction in the overall project LUEC. The IESO is cognizant of the potential for anticipated carbon policies in the province of Ontario to positively impact the business case for new hydroelectric generation development. It should be noted that the IESO is not currently active in procuring provincial generation resources for capacity or energy needs. As capacity needs are forecast to arise in the mid-2020s, and as carbon policy is further clarified, alternatives will be evaluated and compared at the appropriate time.

[42] Depending on cost of carbon scenarios

9.4 Community Energy Efficiency Activities

A large number of communities in the Greenstone-Marathon Sub-region do not have access to natural gas delivery infrastructure, and rely on electricity as their primary source of heating. During early engagement activities, the Town of Marathon identified their interest in developing cogeneration to supply some of their community facilities which require a significant amount of heat load thereby creating budgetary constraints for the community.

The electricity infrastructure serving the North Shore sub-system, and Marathon Area sub-system has been determined to be sufficient. The analysis of individual proposals in the absence of power system need is not typically within the scope of an IRRP. However, from discussions with the local community and as part of the IESO's authority to coordinate provincial and regional conservation programs, it was agreed that a high-level analysis to help demonstrate the feasibility of cogeneration opportunities would be valuable within the context of this IRRP.

An analysis is described below to demonstrate the feasibility for cogeneration in the Town of Marathon. A similar methodology may be applied by other communities with no access to pipeline natural gas infrastructure. Details of the step-by-step methodology and analysis are included in Appendix I.

It was determined from the publicly available data reported for the Broader Public Sector regulation for public sector facilities in Marathon that the three largest municipal electricity consumers in Marathon are the hospital, arena/theatre, and high school. These total nearly 50% of the municipal electrical energy use. These facilities and others are also located within a 150 m radius, making logical candidates for a shared cogeneration solution.

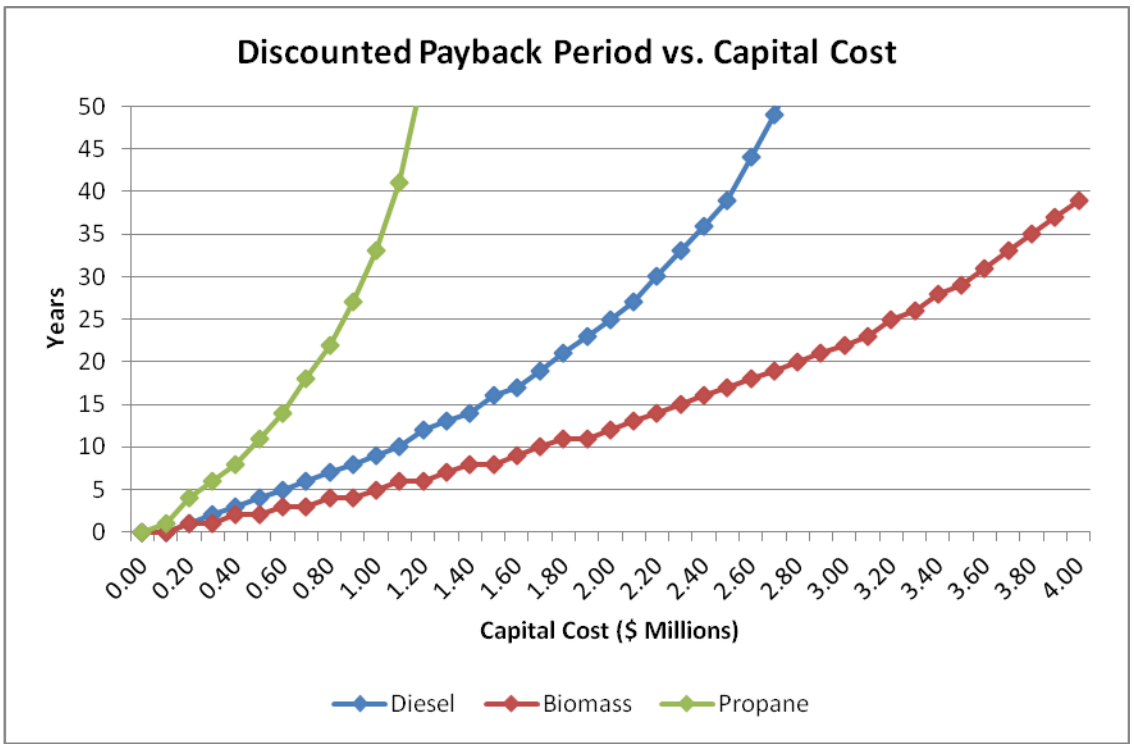
This analysis did not consider the sale of cogeneration services to facilities not reported by the Broader Public Sector regulation (e.g., private businesses), which may help to improve the business case.

Depending on the capital cost of the facility and the type of fuel being considered, a range of payback scenarios may result which are illustrated in Figure 9-4.

It is cautioned that this analysis has been done at a planning-level and investments should not be made solely based on this high level analysis. Furthermore, a number of development projects, regulatory proceedings, and legislative processes are underway that may impact this analysis. This includes the possible development of Liquefied Natural Gas infrastructure and delivery, the possible expansion of natural gas service to Ontario communities that are currently not served, the impact of cap and trade regulation, and the evolution of carbon policy.

Therefore, the Town of Marathon may find value in undertaking a detailed study of cogeneration solutions in the community, considering public and private customers, and the associated risks. Noteworthy, is that the IESO has funded engineering studies to support cogeneration initiatives through the "Save on Energy" program which are accessible through its website.[43]

Figure 9-4: Marathon Cogeneration Discounted Payback Period Analysis



9.5 Actions to Maintain Flexibility for the Medium and Long Term

The following actions are proposed to maintain flexibility for accommodating additional growth, within the study area for the medium and long term:

- Mine developers in Greenstone retain the option of upgrading circuit A4L from Alexander SS to Beardmore TS as an economic alternative for supplying the Beardmore mine and additional mining in Greenstone. Mine developers should engage Hydro One,

[43] https://saveonenergy.ca/Business/Program-Overviews/Process-and-System-Upgrades/Engineering-Studies.aspx

the transmission owner of circuit A4L, recognizing that a lead-time of approximately five years is required if they wish to pursue this option.

- Those investigating a multi-use infrastructure corridor to the Ring of Fire consider the need for a new transmission line, as outlined in this plan. The IESO is available to provide planning advice associated with a new transmission line on this corridor. The IESO will also update electricity plans associated with this corridor as additional information becomes available.
- The Town of Marathon conduct a detailed study of community energy options related to cogeneration. The IESO can support studies within the context of electricity planning, demand, and reliability, as well as IESO-coordinated conservation programs and funding.

The IESO does not have authority to direct or implement these actions on behalf of the parties indicated. These actions are documented to provide customers, communities, and stakeholders with the IESO's independent assessment of the technically feasible and least societal cost options for meeting the various needs in the area.

10. Community and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date and next steps for the Greenstone-Marathon IRRP.

A phased community engagement approach was undertaken for the Greenstone-Marathon IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 10-1: Summary of the Greenstone-Marathon Community Engagement Process

Creating Transparency: *Creation of Greentone-Marathon IRRP Information Resources*	• Dedicated Greenstone-Marathon IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members • Dedicated web page created on Hydro One website • Self-subscription service established for the Northwest Ontario planning region for subscribers to receive regional planning updates • Status: complete
Engaging Early and Often: *Municipal & First Nation Outreach*	• Early engagement on regional planning and the draft Northwest Ontario Scoping Assessment Report (October - December 2014) • Two group meetings held with municipalities from across the planning region held in Greenstone and Marathon (April 2015) • Meetings held with First Nation communities throughout the planning region (May 2015 -February 2016) • Status: initial outreach complete; dialogue continues
Bringing Communities to the Table: *Broader Community Outreach*	• Greenstone-Marathon Local Advisory Committees (LAC) formed in spring 2015; dedicated Greenstone-Marathon engagement page added to IESO website • Three LAC meetings held to discuss the Interim IRRP released June 2015, further development of the near-term options and priorities for the long-term, as well as a review of draft IRRP • LAC meetings are open to the public and broadcast via live webinar; materials are posted to the engagement webpage • Status: begun in spring 2015; on-going

10.1 Creating Transparency

To start the dialogue on the Greenstone-Marathon IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO website including a map of the regional planning area, information on why an IRRP was being developed for the Greenstone-Marathon Sub-region, the IRRP terms of reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader Northwest Ontario planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

10.2 Engage Early and Often

Early communication and engagement activities for the Greenstone-Marathon IRRP were initiated in October 2014 as part of a series of meetings with communities and stakeholders to discuss electricity planning initiatives across Northwest Ontario. The main objective of the meetings from a regional planning perspective was to introduce attendees to the regional planning process. This included the Northwest Ontario Scoping Assessment process for the regional planning studies being initiated in the area, as well as discussions of upcoming engagement activities. Various meetings were held with a broad range of attendees including municipal representatives, First Nation and Métis community members, federal and provincial representatives, electricity customers, CVNW, transmission and generation project developers, and others.

10.2.1 Northwest Ontario Scoping Assessment Outcome Report

The draft Northwest Ontario Scoping Report was posted to the IESO website in December 2014 for comment. Feedback on the draft report was received from the Municipality of Greenstone indicating the need for an accelerated timeline for the Greenstone area plan. In response, the Working Group added an interim document on the near-term elements to the Terms of Reference for the Greenstone-Marathon IRRP. The Interim Greenstone-Marathon IRRP was released June 22, 2015 in response to this request.

10.2.2 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In April 2015, the Working Group held group municipal meetings in Marathon and Greenstone to discuss the findings and options developed to date. Attendees were generally pleased with the progress of the plan, and indicated that planning needs to be cognizant of the implementation risks involved and the need to ensure electricity prices do not increase unnecessarily.

10.2.3 First Nation and Métis Community Meetings

On May 11, 2015 the IESO met with the Board members of WZI and Chiefs Pelletier, Gustafson and Nelson of Red Rock Indian Band, Whitesand First Nation and AZA, respectively. WZI is an economic development corporation established by five First Nations: Red Rock Indian Band, BNA, BZA, AZA, and Whitesand First Nation. The feedback received from WZI focused on the desire for infrastructure to be planned so that environmental disturbance is minimized. WZI requested that, when possible, existing infrastructure corridors are optimally utilized before developing a new corridor resulting in a new disturbance.

On May 11, 2015 the IESO met with Chief Duncan Michano of Ojibways of Pic River First Nation. A follow-up discussion with additional community members may be required. The IESO remains open to additional meetings to support further engagement of the IRRP.

On May 12, 2015 the IESO met with a Councilor and staff of Pic Mobert First Nation. The feedback from this meeting was that decisions regarding electricity should not result in unnecessary price increases and the need for greater community-level economic development opportunities for First Nation communities in general.

On July 7, 2015 the IESO met with the Highway 11 First Nations Energy Working Group, which consisted of representatives from the following First Nation communities: Aroland, Constance Lake, Long Lake #58 and Ginoogaming. The feedback shared was that there is a preference by the Highway 11 First Nations Energy Working Group that grid-connected solutions be pursued by the customers. The Highway 11 First Nations Energy Working Group also expressed an interest in developing some solutions consistent with the IRRP recommendations. Finally, the Group emphasized their support for long-term supply options to the Ring of Fire and the need to coordinate planning efforts.

On November 11, 2015 the IESO met with Chief Richard Allen and representatives from Constance Lake First Nation, as well as representatives of Long Lake #58 First Nation. The feedback shared by some representatives was that they would like to see a connection from Longlac TS (Greenstone) to Hearst TS (interconnected to the Northeast power system). The IESO responded that this would not be technically feasible because the respective 115 kV systems are equipped with relatively small conductors and by effectively shorting the connection between the Northwest and Northeast along a new 115 kV link would result in overloading of that connection and possible stability concerns. The IESO indicated that reinforcement of the connection between the Northwest and Northeast systems is being considered through the planning of the expanded East-West Tie. There was also discussion around the possible option of connecting the remote Matawa communities via a north-south corridor option from near Geraldton to the Ring of Fire via a logging road that passes by

Eabametoong First Nation. The IESO will investigate this option as part of its continued support for the economic connection plan for remote First Nation communities.

On February 3, 2016 the IESO met with representatives of Long Lake #58 First Nation. Updates were shared by the IESO and Long Lake #58 regarding the progress made, and confirming the IESO's opinion regarding options and recommendations.

The IESO invited all other local First Nations communities and Métis councils to similar meetings and remains open to further engagement with those communities on the plan.

The IESO has been made aware of a Matawa Chief's resolution and a WZI Board resolution. Both these resolutions indicate support for grid-connected electric supply solutions for the region, and opposition to off-grid solutions. The WZI Board resolution specifically supports the new 230 kV East of Nipigon line option identified in the IRRP. The IESO will continue to work with the local First Nations and Métis in future planning initiatives.

10.3 Bringing Communities to the Table

To continue the dialogue on regional planning, two Local Advisory Committees - a general LAC and a First Nations LAC - were established for the Greenstone-Marathon regional planning area in spring 2015. The role of LACs is to provide advice and recommendations on the development of the regional plan as well as to provide input on broader community engagement. General LACs are comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. First Nations LACs are comprised of representatives from the First Nation communities in the planning area. All general LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's Greenstone-Marathon engagement webpage.[44] The Greenstone-Marathon general LAC meetings are also broadcast as live webinars to allow participation from across the planning region.

Development of the Greenstone-Marathon general LAC was completed through a request for nominations process promoted by the following activities: advertisements in five local newspapers across the planning area and one Thunder Bay newspaper; digital (website) advertising in eight communities throughout the planning area; emails sent to municipal representatives across the region; and an e-blast sent to the IESO's Northwest Ontario

[44] http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

subscribers list. Each Métis council in the Greenstone-Marathon area appointed a member of their community to the General LAC. The development of the Greenstone-Marathon First Nation LAC was established through a letter to the leadership of each First Nation in the Greenstone-Marathon area inviting them to appoint a representative to the First Nations LAC. The First Nations LAC then appointed members to the general LAC.

On June 29, 2015, following the release of the Interim Greenstone-Marathon IRRP, the IESO held the first LAC meetings in Nipigon. The focus of these meetings was to introduce the regional planning process to the newly formed LACs and review the newly released Interim IRRP. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.[45]

On November 24-25, 2015 the IESO held the second LAC meetings at the Red Rock Indian Band Lake Helen Reserve. The focus of these meetings was to discuss and receive feedback on the development of the medium and long-term options for the IRRP. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.

On May 11-12, 2016 the IESO held the third LAC meetings at the Red Rock Indian Band Lake Helen Reserve. The focus of these meetings was to discuss and receive feedback on the full set of recommendations to be included in the IRRP prior to finalizing the plan. The LAC members decided to produce a report outlining the local socio-economic impacts of the electricity solutions being explored in this IRRP and compliment the Working Group's technical and economic analyses. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.

Copies of the meeting summaries from the Greenstone-Marathon general LAC meetings can be found in Appendix K.

Moving forward, the Working Group will present the final IRRP to both of the Greenstone-Marathon LACs and discuss with members how they would like to continue the dialogue on regional planning in the area following the completion of the plan.

The IESO is committed to undertaking early and sustained engagement to enhance regional electricity planning. Further information on the IESO's regional planning processes is available on the IESO website. Additional information on outreach activities for the Greenstone-

[45] http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

Marathon IRRP can be found on the webpage and updates will continue to be sent to all Northwest Ontario email subscribers.

10.4 Additional Meetings and Presentations

The IESO recognizes CVNW's unique mandate that includes investigating and making recommendations to NOMA on issues related to energy in the Northwest Ontario Region. The IESO continues to meet regularly with CVNW to discuss the status of electricity planning for northwestern Ontario.

The IESO also presents regularly at the NOMA Spring Annual General Meeting and Fall Regional Conference, the Association of Municipalities of Ontario ("AMO") conference, as well as the Ontario Mining Association ("OMA") Conference, among others. These presentations have included high-level status updates on the development of the Greenstone-Marathon IRRP, along with other electricity topics.

11. Conclusion

This report documents an IRRP that has been carried out for Greenstone-Marathon, a sub-region of the OEB's Northwest Ontario planning region. The IRRP identifies electricity needs in the Greenstone-Marathon Sub-region over the 20-year period from 2015-2035, recommends a plan to address near-term needs, and identifies actions to retain economic alternatives for the medium and long term.

Implementation

Implementation of the near- and medium-term plan requires action from the industrial developers. This action consists of customers establishing a commercial agreement for the facilities required to provide the required electrical service. These agreements may include the following elements.

Stage	Recommended Near-Term Facilities	Implementation Agreement
Stage 1	Synchronous condenser or STATCOM	Relevant agreements such as, but not limited to, Reactive Power Service and/or Capacity Agreement
	New 2x10 MW gas engine generating facility	Relevant agreements such as, but not limited to, Capacity and Energy Agreement
Stage 2	New 230 kV line, 115 kV line, 230/115 kV autotransformer station, switching, and voltage control devices	Detailed planning as appropriate, Connection Application, Connection Assessment and Approvals, Cost Recovery, and other agreements consistent with TSC
Medium-Term Actions		**Implementation Agreement**
Mine developers in Greenstone should retain the option of replacing sections of A4L[46]		Detailed planning as appropriate, Connection Application, Connection Assessment and Approvals, Cost Recovery, and other agreements consistent with TSC

[46] This facility is not required if Stage 2 is developed.

The IESO will provide support to individual customers and proponents within the context of the Working Group's recommendations as documented in the IRRP. The IESO does not have the mandate to procure on behalf of individual customers.

The IESO will continue to participate in planning activities related to long-term initiatives such as supply to the Ring of Fire, and community energy efficiency projects.

First Nations and Métis, Community, and Stakeholder Engagement

This report documents the engagement that has been conducted to support the development of the Greenstone-Marathon IRRP.

The IESO will continue to engage First Nation communities, Métis community councils, as well as municipalities and other major interest groups through the LAC and individual meetings as requested.

The LAC meetings and engagements with First Nation communities, municipalities, industry, and stakeholders have provided valuable feedback on the 2015 Interim Plan and input in the development of this IRRP. The Greenstone-Marathon LACs have undertaken a complimentary socio-economic document. The IESO looks forward to subsequent meetings with the two Greenstone-Marathon LACs and continued engagements with communities and stakeholder in the area to discuss the recommendations included within this IRRP, and the future implementation of this plan.