APPENDIX B

DRAFT TECHNICAL REPORT AND BUSINESS CASE FOR THE CONNECTION OF REMOTE FIRST NATION COMMUNITIES IN NORTHWEST ONTARIO

FOR

NORTHWEST ONTARIO FIRST NATION TRANSMISSION PLANNING COMMITTEE

AUGUST 21, 2014

CONTENTS

1.0 EXECUTIVE SUMMARY

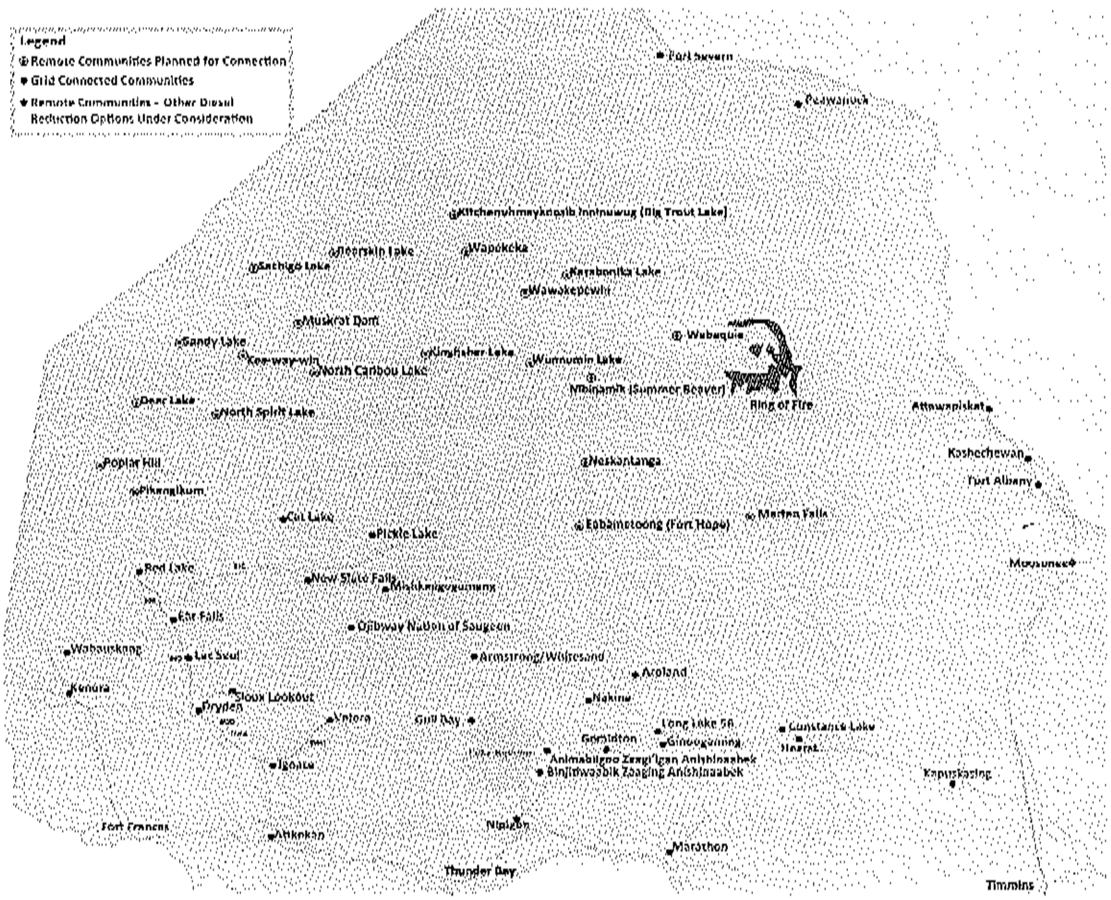
In many of the remote First Nation communities located in northwest Ontario, diesel fuel generators are relied upon to provide electricity. Due to the drawbacks associated with diesel generation, extending Ontario's transmission system to these communities is becoming an increasingly attractive option. This Technical Report and Business Case is the result of a joint planning initiative involving representatives from the northwest Ontario remote First Nations communities that are not currently connected to the provincial electricity grid, and the Ontario Power Authority ("OPA"). This Technical Report and Business Case for Connection of Remote First Nation Communities in Northwest Ontario ("Remote Community Connection Plan" or "Plan") is intended to establish, at a planning level of certainty, the technical and economic feasibility of connecting remote First Nations communities in northwest Ontario to the provincial electricity grid.

There are 27 remote First Nation communities in northwest Ontario with electricity supply, 25 of which are currently not connected to the provincial electricity grid and use local diesel generators for electricity. These remote First Nation communities ("remote communities") are considered remote because of their distance from established transportation and / or energy infrastructure, with most relying on winter roads to transport goods and supplies. Two of these 27 communities (Cat Lake and Slate Falls) were once supplied by diesel generation but have subsequently become connected to the Ontario electricity grid. Figure 1 shows the location of the 25 northwest Ontario remote communities.

Diesel generation that is used to supply electricity in remote communities is on average the highest cost electricity generation resource currently supplying Ontario customers. Typically, diesel generation costs are three to ten times higher than the average cost of the provincial generation supply mix.

Due to forecast demand growth in these communities, the volume of fuel required for electricity generation is expected to increase by about 450 percent over the 40 year planning period. This increase in fuel consumption will pose significant additional challenges in delivering fuel to remote communities. The existing winter road system is approaching its capacity to transport fuel for generation and other uses to remote communities. Therefore, the additional fuel that would be required in the communities is expected to increase the percentage of fuel that must be delivered by air tanker, as winter roads are highly utilized for fuel transport. The cost of transporting diesel by air tanker is many times higher than by trucking on winter roads.

Figure 1: Northwest Ontario Remote Communities



Source: OPA[1]

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[1] Whitesand First Nation and the Town of Collins are connected to the generating station at Armstrong; however the station is not connected to the provincial grid.

The cost of supplying the remote communities under the current arrangement has been estimated for 2013 to be about $90 million per year and this is expected to increase substantially given the four-percent annual growth rate in electrical demand expected over the planning period.

1.1 Key Plan Highlights

- Diesel generation for electricity supply in remote communities is on average the highest cost electricity resource in the province. It is approximately three to ten times higher than the provincial average.
- As a result of the high cost for diesel-generated electricity supply, there is an economic case for connecting up to 21 of 25 remote communities in northwest Ontario to the provincial electricity grid.
- Transmission connection of these 21 communities would result in a savings of about $1 billion over 40 years relative to continuing to supply them with electricity using local diesel generation. This is a reduction of 30 to 40 percent over the planning period.
- The $1 billion cost savings reflects only the avoidable cost of diesel fuel and system expansion. It does not reflect the additional economic, societal, developmental and environmental benefits that would also arise from transmission connection of remote communities.
- The connection plan would have a 20-25 year payback period
- Three subsystems were developed for the purpose of identifying communities which could be technically served by the existing provincial electricity grid: Pickle Lake, Red Lake and Ring of Fire subsystems.
- Radial lines from system supply points at Red Lake, Pickle Lake and / or Marathon / Nipigon to the communities in these subsystems were found to provide the best overall balance of cost, operability and reliability.
- Uncertainty analysis indicates that under a wide range of probable input

assumptions, transmission connection is expected to cost less than continuing to supply the communities using diesel generation with over 90 percent probability.

- The financial benefits of connecting remote communities will accrue to the parties that currently fund their electricity systems, which are most notably, the Government of Canada and Ontario electricity customers.
- The uncertainty range of continued supply by diesel is much larger than transmission connection. Transmission connection fixes most of the 40 year project costs at the time of construction, and future costs are more certain.
- For the four communities that are not economic to connect at this time, renewable resources can be used to reduce diesel fuel consumption and lower the cost of electricity supply to the community. OPA will work with each individual community to determine the optimum community-specific solution through community engagement.

1.2 Existing Costs and Funding Structure for Electricity Supply in Remote Communities

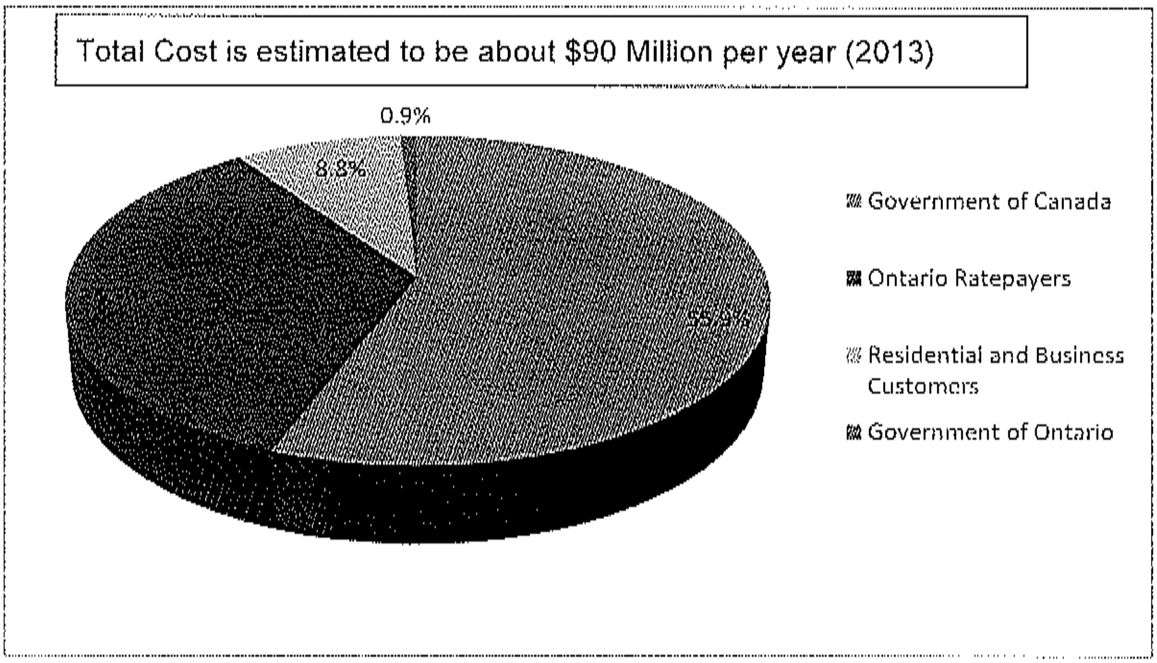
The parties that currently fund the electricity systems in these communities are:

- The Government of Canada, through Aboriginal Affairs and Northern Development Canada ("AANDC"). This is the primary funding source for remote communities operated as Independent Power Authorities ("IPA"s)
- Ontario electricity customers, through a funding mechanism called Rural or Remote Rate Protection ("RRRP"). For the communities discussed in this Plan, this funding mechanism is only available in those remote communities served by Hydro One Remote Communities Inc. ("H1RCI")
- The Government of Ontario and the Government of Canada, through higher electricity rates for government premises in the remote communities. H1RCI has an Ontario Energy Board ("OEB") -approved rate for these customers called the "Standard A" electricity rate. This rate has historically been set above cost.

- Remote community customers in both IPAs and in remote communities served by H1RCI. Remote community customers served by H1RCI pay rates similar to other Ontario ratepayers, even though cost of supply is higher, due to the support provided by RRRP. Rates paid by customers in IPA communities vary by community, some pay fixed rates and others pay rates based on consumption.

The estimated current allocation of the expenses by funding party is illustrated in Figure 2 below.

Figure 2: Estimated Current Share of Annual Cost of Diesel Generation in the 25 Remote Communities by Funding Source



Source: Ontario Ministry of Energy[2]

[2] IPA costs were estimated based on the assumption that they are similar to H1RCI costs per MWh of consumption using values reported in H1RCI's 2013 Cost of Service Application and the Decision and Rate Order. A cost adder of $0.2 per liter was assumed to be the cost difference reflecting inefficiencies associated with IPA diesel systems.

1.3 The Study Process

To determine if there is an economic case for connecting the 25 remote communities to the provincial electricity grid, the OPA and representatives from the remote communities and local tribal councils agreed to form a working group called the Northwest Ontario First Nations Transmission Planning Committee ("Committee"). As a member of the Committee, the OPA's role was to conduct the technical and economic evaluation of electricity supply options for these remote communities. Representatives from the First Nation communities and tribal councils provided oversight and guidance for the analysis and contributed their local knowledge of community growth, quality of electricity service, energy costs, environmental and societal impacts as well as the viability of electricity supply options.

In conducting the analysis, the following general process steps were followed:

1. An estimate of the cost of continuing to supply the 25 remote communities with diesel-fuelled generation over the 40 year planning period was developed.

2. Integrated solutions of conservation, transmission and distribution options were then developed for connecting communities to the provincial electricity grid. These options were developed to ensure that the communities could be served in accordance with the supply standards of the province. The options were refined with input from the Independent Electricity System Operator ("IESO") to ensure costs were included for equipment that may be needed to effectively operate and maintain any new portion of the transmission system. The options were also refined with input from the Committee and community members through engagement, to ensure that the proposed transmission and distribution line routings were practical and accounted for known community and environmental impacts. Conservation was considered to help relieve interim supply constraints and manage long-term costs for the communities.

3. Supply options for integrating renewable generation with the existing diesel systems in the remote communities were developed on a community-by-community basis.

The least-cost scenario (resource type and size) was chosen for comparison with transmission connection and continued diesel supply alternatives.

4. An analysis was also conducted to assess the cost and benefit of supplying subsystems of remote communities using a micro-grid in combination with local hydroelectric power. This alternative was determined not to be cost-effective and was not considered further in the analysis.

5. Financial models were developed to compare different scenarios for supplying the communities.

6. An uncertainty analysis was conducted to understand the relative cost risks of remaining on diesel supply, integrating renewable resources, or connecting to the provincial electricity grid.

7. For the four remote communities that were determined not to be economic to connect at this time, an initial assessment of the costs and benefits of displacing diesel generation with local renewable resources and / or a combination of renewable resources and storage was conducted.

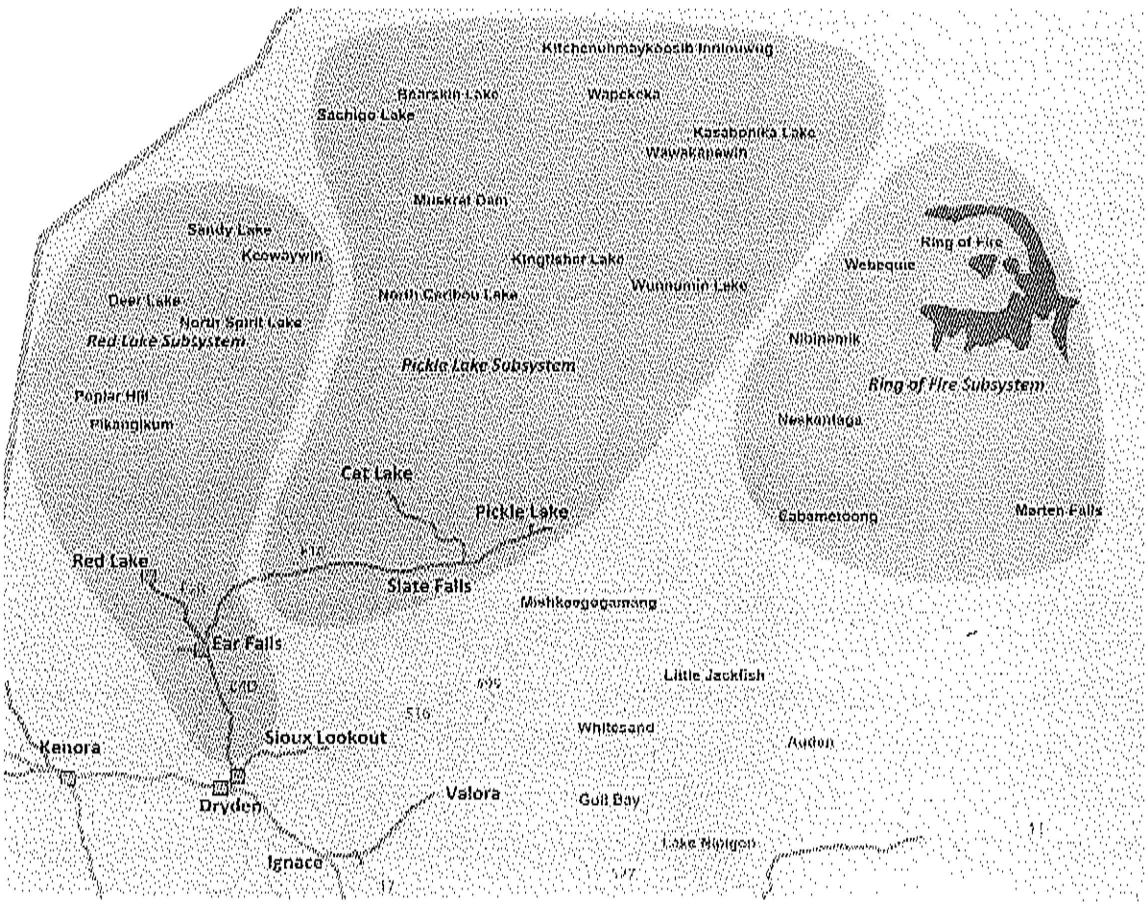
Step 2 resulted in grouping the remote communities into three subsystems, the Red Lake, Pickle Lake and Ring of Fire subsystems, seen in Figure 3 below. These subsystems identify remote communities that are technically feasible to connect to existing transmission system termination points, while meeting the supply standards established for the provincial power system.

Technical feasibility analysis indicates that:

- The Red Lake subsystem can best be served from the transmission system termination point at Red Lake.
- The Pickle Lake subsystem can best be served by the transmission system termination point at Pickle Lake.

- The Ring of Fire subsystem can be served from the transmission system termination point at either Pickle Lake or from the 230 kV transmission system to the south in the vicinity of Nipigon or Marathon.

Figure 3: Community Subsystems



Source: OPA

1.4 Economic Analysis

The OPA, supported by the Committee, completed a detailed economic analysis comparing the avoidable costs[3] of continued diesel generation against the capital and operating cost of transmission connection. This analysis indicates that there is an economic case for connecting up to 21 of the 25 remote communities to the provincial electricity grid. The analysis also indicates that there are opportunities for existing / future industrial customers and these remote communities to share transmission facilities as well as their capital and operating costs. These studies indicate that transmission connection of the 21 remote communities would result in a savings of about $1 billion over the 40 year planning period, when compared to the cost of continuing to supply the communities using diesel fuel.

The uncertainty analysis mentioned in process step 4 of Section 1.2, determined that connection poses less risk than remaining on diesel over the long term, and similarly, would be less risky than relying on renewable resources or micro-grid options, which would only partially offset the heavy reliance on diesel fuel.

With respect to the four remote communities that were determined to be uneconomic to connect at this time, analysis revealed that displacing diesel with renewable resources, especially small-scale wind generation, can be economic. However, detailed studies for each of the four communities will be required to determine specific solutions. In a directive dated December 16, 2013, the Minister of Energy instructed the OPA to "work with those remote First Nation communities where transmission connection is not identified as economic in the OPA's plans and other appropriate parties, in order to develop and implement solutions for on-site renewable generation that reduce their dependency on

[3] Avoidable costs of diesel operation are the generation related costs (fuel, variable operations and maintenance, variable overhead, etc.) that can reasonably be expected to be eliminated when an alternate supply source, such as a transmission connection, is used to supply electricity in remote communities.

diesel fuel." The directive requires the OPA to complete plans for these four communities by the end of 2014. As of summer 2014, development of these plans was underway.

1.5 Key Assumptions

For the purpose of developing this Plan, the following key assumptions underlie the analysis:

- The nature of the power system remains the same for the entire planning period as when the report was written, including the ability of the provincial transmission system to accommodate connection and forecast load growth of the communities recommended for connection;
- An outlook or planning period of 40 years (2014 to 2054);
- An average long-term inflation rate of two percent. All prices and costs have been adjusted or present valued to a 2014 base year in 2014 dollars;
- Community annual electricity demand growth of four percent after 2013, which is consistent for all options;
- 70 percent of fuel will be delivered by air and 30 percent by winter road for all years in the planning period;
- The OPA's Ontario electricity price forecast (based on current energy sector plans and policies anticipated to be in place until 2031);
- A social discount rate of four percent in real dollars, which is consistent with social-based analysis of this nature routinely conducted by the OPA;
- Diesel fuel price forecast growth is in line with the U.S. Energy Information Agency Annual Energy Outlook Early Release 2013 report. The fuel price in Thunder Bay was used as a basis;
- In the case of transmission connection, diesel backup will be required approximately five percent of the time. In the renewable resources options, diesel will be required at least 50 percent of the time;
- During transmission construction, financing costs will be incurred until the date of in-service at a real rate of approximately 3.4 percent. Debt is assumed to be paid in the year of in-service of the transmission facilities.

1.6 Summary of the Transmission Supply Options

Radial lines to the communities from system supply points at Red Lake, Pickle Lake and Marathon or Nipigon were found to provide the best overall balance of cost, operability and reliability.[4] Loop connection configurations were evaluated; however, they were found to cost substantially more and would not materially improve reliability relative to the radial configuration that is recommended. The radial configurations proposed would meet all supply criteria established for the Ontario power system.

1.6.1 Connection Details for the Pickle Lake Subsystem

The Pickle Lake subsystem includes 10 remote communities north of the Municipality of Pickle Lake. Connecting these 10 communities requires upgrading the transmission system to Pickle Lake by incorporating a new 115 kV or 230 kV line from the Dryden / Ignace area. This new transmission line to Pickle Lake was identified as a priority project in the 2010 and 2013 Long-Term Energy Plans, issued by the Ontario government. This new line has the capability of economically incorporating the five remote communities in the Ring of Fire subsystem in addition to the Pickle Lake subsystem. Current demand forecasts for the Pickle Lake area indicate that a line built to 230 kV standards will be required to meet forecast demand growth in the area to 2033.

Wataynikaneyap Power, a First Nations-owned transmission development company that is currently working to connect communities within the Pickle Lake and Red Lake subsystems, has developed transmission routing for these lines. This routing configuration has been used in the analysis for this Plan. An illustrative diagram of this supply option is provided in Figure 4 below.

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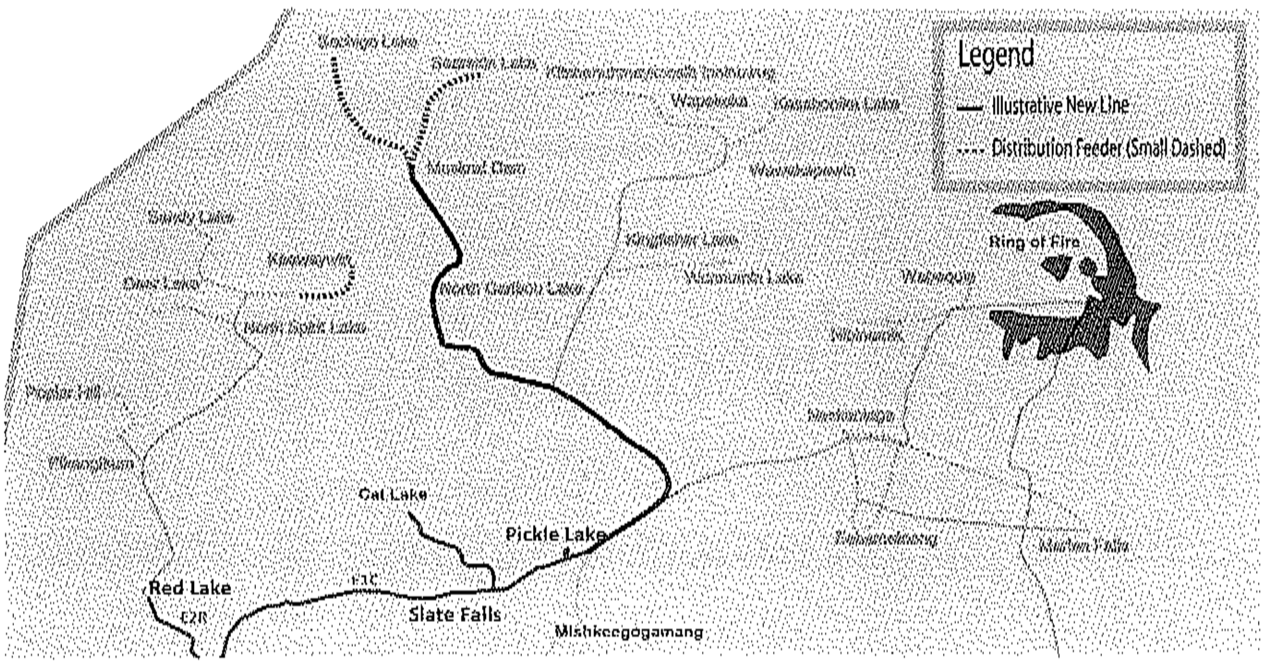
[4] A radial transmission system is one where one or more customers (generators or load) are connected to a single point on an electricity system, which differs from a network system where there are multiple connection points.

The line configuration begins in Pickle Lake and runs north until it branches at a point south of North Caribou Lake. The northwest branch would connect the communities of North Caribou Lake, Muskrat Dam, Sachigo Lake and Bearskin Lake. The northeast branch would connect the communities of Kingfisher Lake, Wunnumin Lake, Wawakepewin, Kasabonika Lake, Wapekeka, and Kitchenuhmaykoosib Inninuwug.

A transmission line to Pickle Lake would also be capable of supporting a transmission line connecting the remote communities within the Ring of Fire subsystem. North-east of Pickle Lake, the transmission line would split into two branches, as shown in Figure 4. This east bound line would connect the communities of Neskantaga, Nibinamik, Webequie, Eabametoong and Marten Falls.

Figure 4: Pickle Lake Subsystem Supply Option

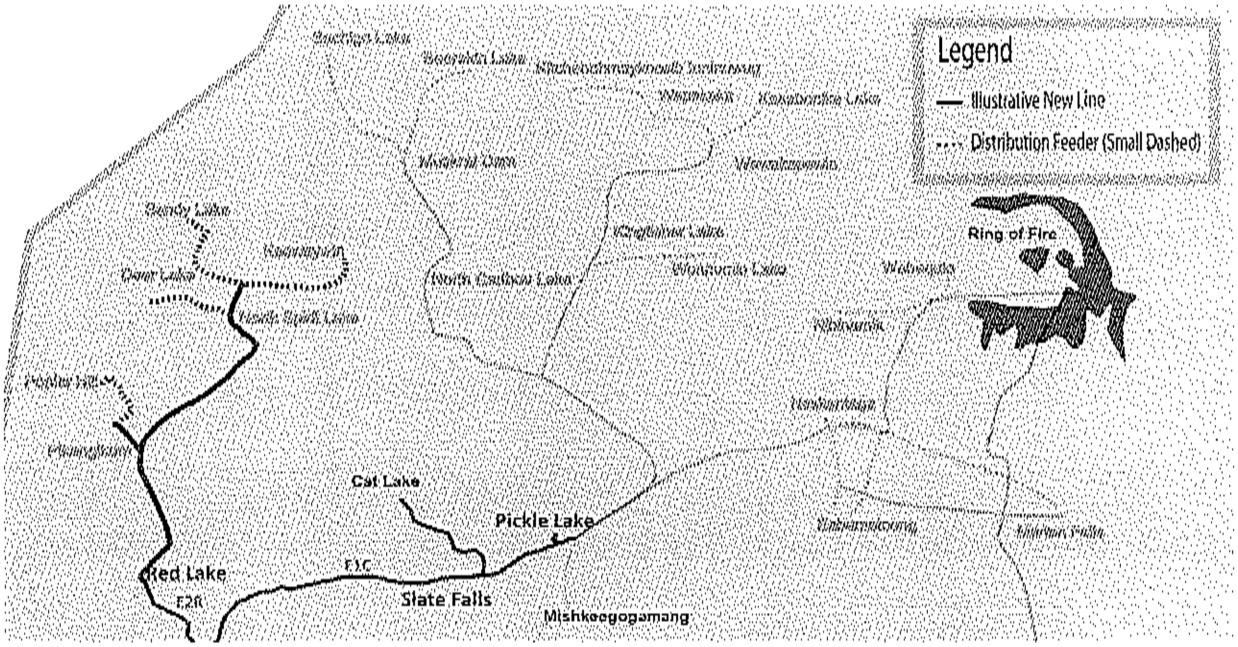


Source: OPA

1.6.2 Connection Details for the Red Lake Subsystem

The Red Lake subsystem includes six remote communities directly north of the Municipality of Red Lake. Connecting these six communities requires upgrading the existing transmission system serving Red Lake and / or Pickle Lake[5]. Upgrades to the transmission lines serving Red Lake are identified as projects in the planning stage in the 2013 Long-Term Energy Plan.

Figure 5: Red Lake Subsystem Connection Concept



Source: OPA

Transmission to the Red Lake subsystem would consist of a new 115 kV line extending from the existing transmission system at Red Lake Transformer Station ("TS") to Pikangikum, then to North Spirit Lake, terminating at a new TS south-east of Sandy Lake, as shown in Figure 5. Upgrades to the existing transmission lines serving Red Lake would be required to enable the connection of the six remote communities in this subsystem.

[5] The new line to Pickle Lake can create some capacity in the Red Lake area (when E1C, the line between Ear Falls and Pickle Lake becomes supplied by the new line to Pickle Lake). The availability of capacity in the Red Lake area following the installation of the new line to Pickle Lake will depend on timing of applications from customers in the Red Lake area.

1.6.3 Connection Details for the Ring of Fire Subsystem

The Ring of Fire subsystem includes five remote communities as well as the area of potential mining development for the Ring of Fire area. If a north-south transmission line is developed to supply mining developments in the Ring of Fire area, technical analysis indicates that this line could serve these five communities. The existing 230 kV transmission facilities at both Marathon and Nipigon are potential transmission supply points for the north-south line to the Ring of Fire. As mentioned above, Pickle Lake is also a potential supply point for the five remote communities in the Ring of Fire subsystem.

There are four options for serving the five communities in the Ring of Fire subsystem from the provincial grid.

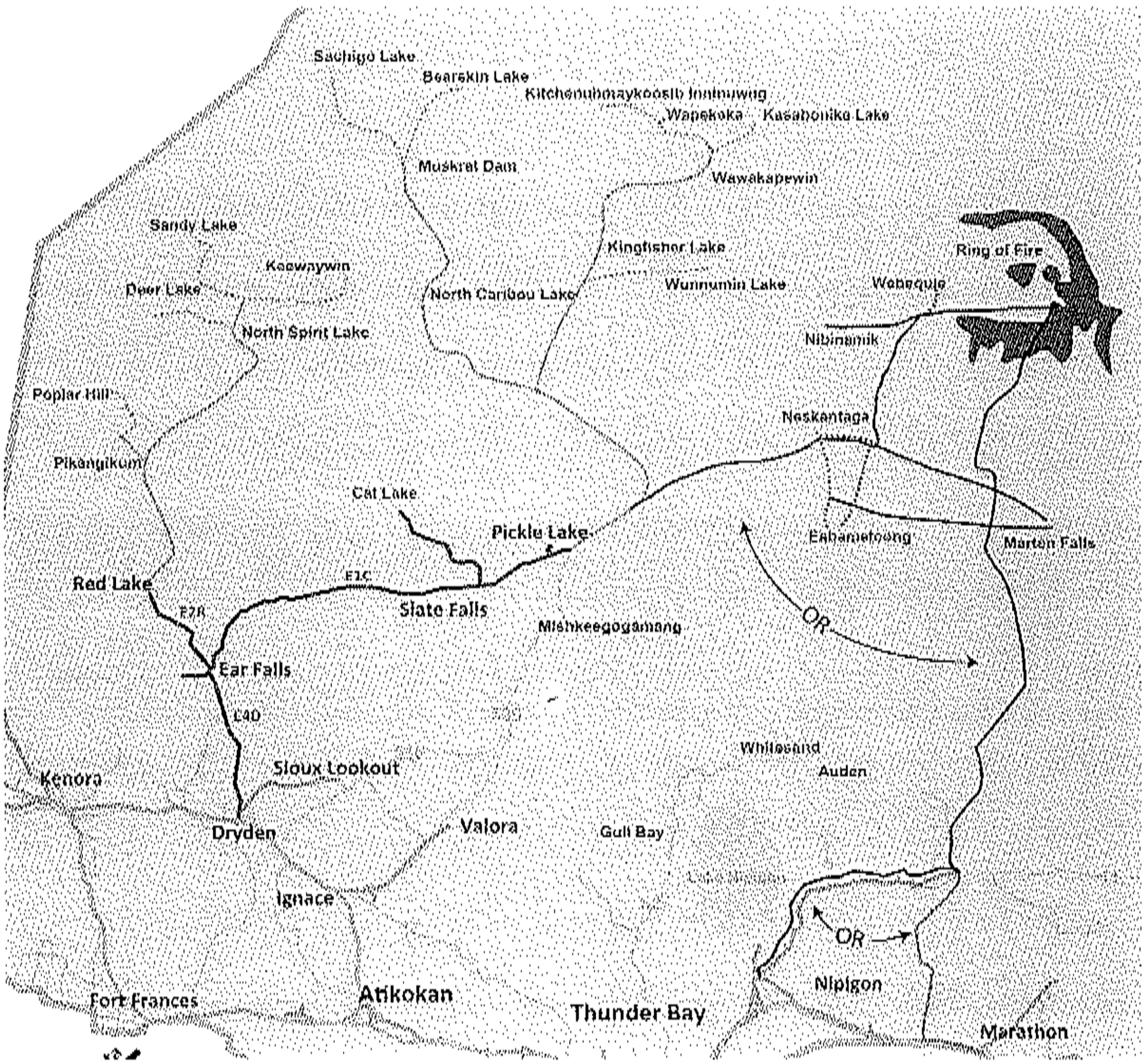
The first option is to build a new 115 kV transmission line from Pickle Lake to the remote communities in the Ring of Fire subsystem. In this option, any mines that may develop at the Ring of Fire would not be connected. As described above, the Pickle Lake area would have to be reinforced by a new 115 kV transmission line from the Dryden area to Pickle Lake at a minimum.

The next three options would connect the remote communities and potential mines in the Ring of Fire subsystem. Given this subsystem's relative proximity to the Nipigon / Marathon area and Pickle Lake, these all represent potential transmission supply points for the subsystem. The options for connecting communities and mines at the Ring of Fire are:

1. A 115 kV line from Pickle Lake to the Ring of Fire subsystem
2. A 230 kV line from Pickle Lake to the Ring of Fire subsystem
3. A 230 kV line from Marathon or Nipigon area to the Ring of Fire subsystem

An illustrative diagram of the supply options for the Ring of Fire subsystem can be found in Figure 6 below. Transmission from Pickle Lake could be built at either 115 kV or 230 kV. It is depicted here by a purple line originating from Pickle Lake. Alternatively, a 230 kV transmission line from either Marathon or the Nipigon area would connect communities and mines (depicted as a blue line).

Figure 6: Supply Options for Ring of Fire Subsystem



Source: OPA

1.7 Technical and Economic Assessment

To facilitate the technical and economic assessment, transmission system capital costs were attributed to potential transmission customers in proportion to their anticipated electricity demand on the new lines. This methodology is consistent with the Ontario Energy Board's cost responsibility principles which are set out in the Transmission System Code.

Table 1: Scope of Proposed Remote Community Transmission Connection Plan

Subsystem	Transmission Line (km)	Distribution Line (km)	Transformer Stations	Distribution Stations
Pickle Lake Subsystem	530	400	4	10
Red Lake Subsystem	260	200	3	6
Ring of Fire Subsystem, Communities Only	210	325	2	5
Ring of Fire Subsystem from Pickle Lake 115 kV	300	350	3	5
Ring of Fire Subsystem from Pickle Lake 230 kV	350	350	3	5
Ring of Fire Subsystem from Nipigon/Marathon 230 kV	700	275	4	5

Source: OPA

The options identified in this Plan require new transmission lines (115 kV and 230 kV), new distribution lines (44 kV or lower), new 115 kV and 230 kV transformer stations and new 44 kV distribution stations to step down the voltage to the existing local community grids. Table 1 above summarizes the line distances and the number of transformer and distribution stations required for each remote community subsystem and scenario.

1.8 Connection Project Capital Cost

Based on the line distances and the number of required station facilities identified in Table 1, the OPA developed a forecast of project capital costs using unit costs developed by an experienced third party engineering consultant (see Table 2 below).

Table 2: Total Project Capital Costs and Contributions from Other Parties Sharing Assets ($2014 millions)

	Contributed Capital from Remote Communities	Contributed Capital from Other Parties	Total Capital
With Ring of Fire Mines	1,060	240	1,300
Without Ring of Fire Mines	1,230	50	1,280

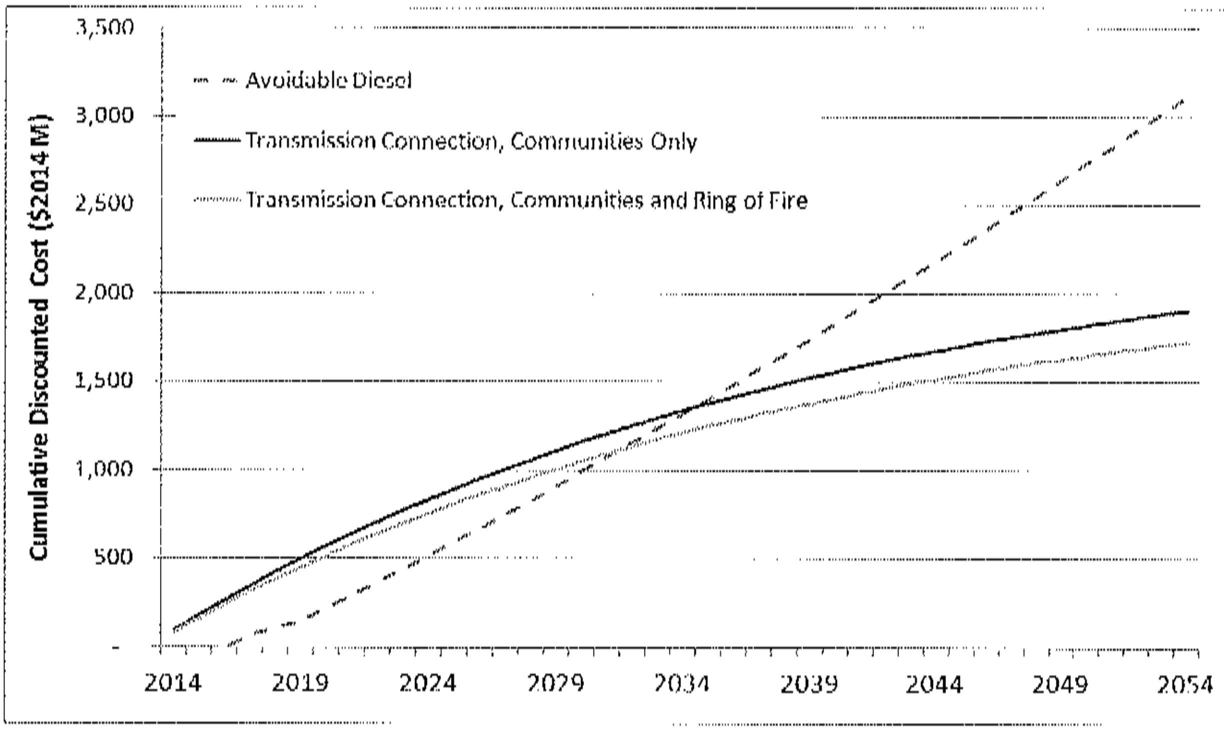
Source: OPA

1.9 Net Benefit

Based on the avoidable diesel costs and the total cost of transmission connection as assessed in this Plan, the cost of the aggregated connection project is expected to break even with the cost of the current diesel generation supply within 20 to 25 years of the communities being connected. Looking further out, the long-term cost of connecting the communities is estimated to be about 30 to 40 percent lower than continuing to power them with diesel generation until 2054. Figure 7 shows the cumulative discounted (present) costs of avoidable diesel supply and the transmission connection scenarios.

A payback period of this duration (20 to 25 years) is reasonable for electricity infrastructure assets that are expected to last at least 50 years before requiring substantial reinvestment or refurbishment. Based on understandings of climate and weather in northwest Ontario, major transmission components can last in excess of 80 years with proper operation and maintenance.

Figure 7: Transmission Connection Breaks Even in 20-25 Years versus Diesel Generation



Source: OPA[6]

The business case for transmission connection developed by the OPA is based solely upon avoidable diesel costs and does not reflect the additional economic, societal, developmental and environmental benefits that would also arise with transmission connection. These may include:

- Reduced infrastructure related barriers to growth;
- Increased economic development opportunities (both within the remote communities as well as regionally);
- Improved social and living conditions for remote community residents;

[6] The transmission costs have been amortized over a 45-year period, reflecting the minimum expected life of transmission assets. This affects the breakeven time by one to two years; however, analysis indicates that breakeven would occur in 20 to 25 years, regardless of this financing assumption.

- Cleaner air and reduced greenhouse gas emissions;
- Reduced future environmental remediation liabilities associated with diesel fuel spills;
- Improved security and reliability[7] of electricity supply.

1.10 Uncertainty Analysis

To determine the degree to which the findings within this analysis are robust, the OPA conducted an uncertainty analysis. This analysis provides a statistical representation of the net present value ("NPV") of the business case over a wide range of assumptions for several key variables, shown in Table 3 below, which were found to be the primary drivers for determining the outcomes. To conduct this analysis, the OPA used a standard uncertainty analysis methodology (known as a Monte Carlo simulation) which is commonly used in business case analysis when there is uncertainty in the input assumptions of a model. The range of costs for each transmission scenario is compared with the diesel case in Figure 9 below.

Table 3: Key Variables for Uncertainty Analysis

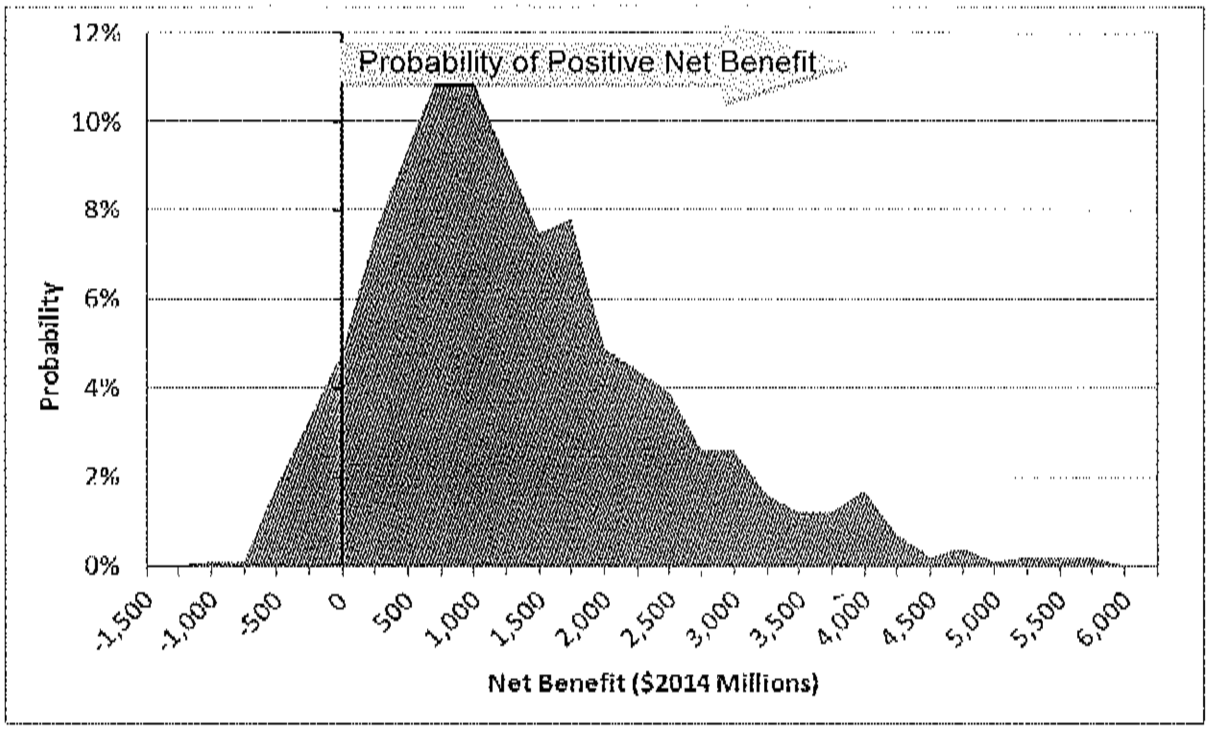
Variable	Average	Distibution Type	90% Interval
Demand Growth	4%	Normal	+/- 4%
Diesel Price Growth	1.20%	Normal	+/- 1%
Transmission Cost	0%	Normal	+/-50%
Renewables Cost	0%	Normal	+/- 20%

Note: The transmission cost variable modifies the assumed cost per kilometer or per station for transmission and distribution facilities. The renewable resources cost variable modifies the assumed cost per kW for new renewable facilities and controls.
Source: OPA

[7] Security of supply is improved for all communities by introducing a second source of supply, transmission, and maintaining diesel as back up. H1RCI communities currently have relatively good reliability. The impact of long transmission lines may result in more unplanned outages. However, with the back-up diesel systems that are recommended, the good reliability can likely be maintained. Transmission is likely to be more reliable than current diesel supply in most IPA communities. This will be discussed in more detail in Appendix B.

These findings indicate that under a wide range of probable input assumptions, transmission is expected to cost less than diesel with more than 90 percent probability.

Figure 8: Net Present Value Distribution of Base Case (Communities Only)

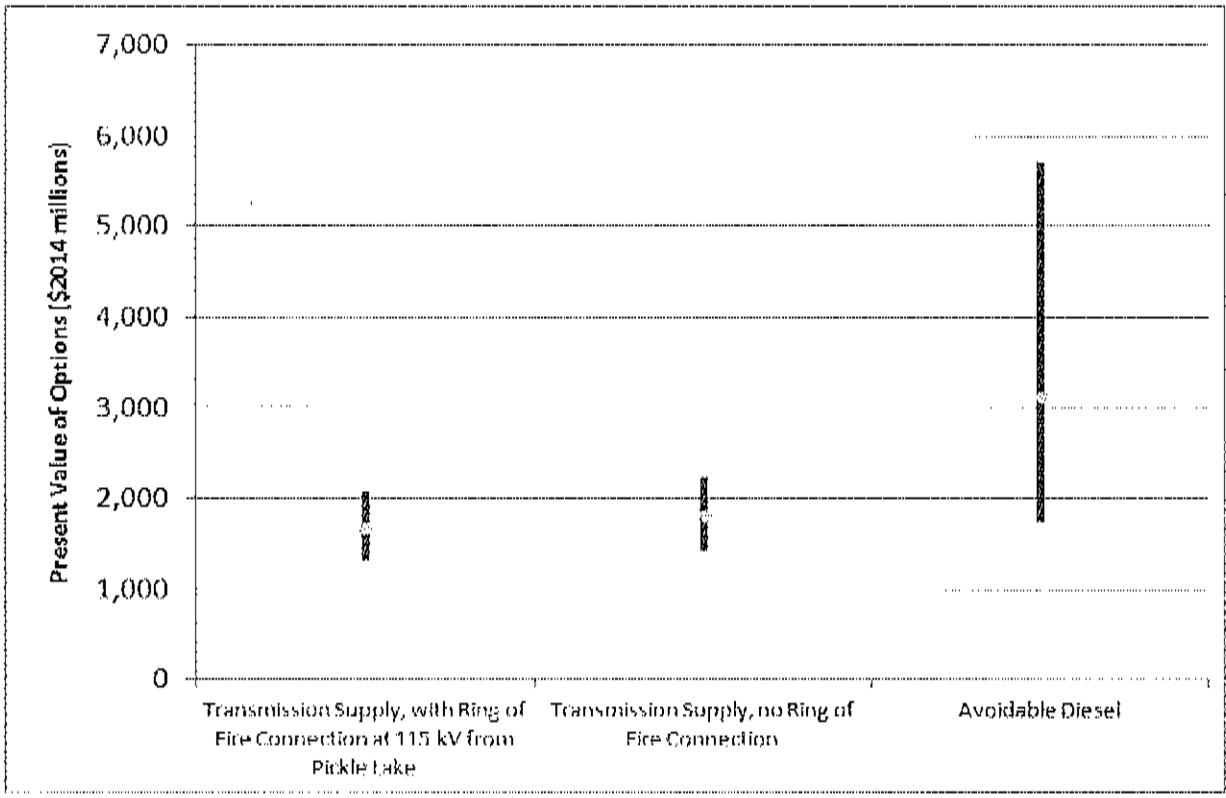


Note: this chart does not include the renewable resources case as the net benefit results are concentrated in the small range of $0M - $500M (98 percent of results) due to the alternative being highly correlated with the avoidable diesel case. Displaying all alternatives would skew the scale of the graphic.

Source: OPA

Further, the range of cost uncertainty for continued diesel use is much greater than for transmission. A large portion of the costs for transmission connection are upfront and do not vary once the communities are connected, whereas diesel costs (fuel, transportation, capital) are spent over time and thus can vary widely over a 40 year planning period. These findings are a strong indicator that net economic benefits of transmission connection will materialize over the 40 year planning period if transmission connection is undertaken.

Figure 9: Distribution of Cost of Transmission Connection versus Avoidable Cost of Diesel Generation, 90 percent Confidence Interval



Source: OPA

1.11 Integrated Renewable Resources with Diesel Generation

The third option that was evaluated for supplying the remote communities was the use of the existing diesel generators in the communities integrated with combinations of local renewable resources as well as battery storage. The objective was to determine if a combination of local renewable resources (and where appropriate, battery storage) could minimize the overall cost of supplying the communities. In all cases, diesel generation would still be needed to meet demand when variable renewable resources are insufficient or unavailable, such as when run-of-river hydro sites have insufficient flow to meet demand or wind is not available. To implement this option, continued investment in diesel capacity would be required to match load growth in each community. The OPA's analysis indicates that renewable generation integrated with diesel is not as cost-effective as transmission connection. The results of this analysis are summarized in Table 4.

It should be noted that renewable generation can economically reduce diesel consumption in the four communities that are not currently economic to connect. The introduction of renewable generation in these communities can improve local electricity supply by reducing the overall cost of supply, as well as the environmental impact of diesel generation. Table 4 shows a cost comparison of the renewable supply options with diesel generation and transmission connection.

Table 4: Comparative Average Total Cost of Electricity Supply For Alternative Supply Technologies

	Average Total Cost of Supply to 2054 ($/kWh)		
	Low	High	Remaining on Diesel Supply
Diesel Generation	1.10	1.20	All
Isolated Wind Integrated with Diesel	0.85	0.95	All
Isolated Solar Integrated with Diesel	1.10	1.20	All
Isolated Wind and Solar Integrated with Diesel	0.85	0.95	All
Hydro Connected to Community Clusters	1.10	1.50	>10
Transmission Connection	0.40	0.50	<~5

Source: OPA

1.12 Community Engagement

It is important to note that the OPA's work on remote connections is a result of a close working relationship with the Committee. Additionally, since the release of a draft version of the Remote Community Connection Plan in summer 2012, the OPA has engaged with many of the remote communities to provide information on the analysis and conclusions in the Plan. The OPA's engagement has varied by community and has included: meetings with Chiefs and Councils, meetings with community members, as well as the providing of information through local radio and television broadcasts. Engagement with community members has often also included the presence of a translator from the community. To date the OPA has engaged with 17 of the communities included in the Plan and overall there has been strong support expressed given the benefits which can be realized. Key concerns raised during engagement included the potential for local renewable energy projects, the impact of transmission lines on the environment, and local job opportunities, among other things. The Remote Community Connection Plan will be finalized only following engagement with all 25 communities.

1.13 Conclusion and Summary

For up to 21 remote communities located in northwest Ontario, transmission connection can result in substantial economic and societal benefits. Given that diesel-generated electricity is one of the most expensive resources in the province, cost savings will result from transmission connection. Including required capital investment, about $1 billion (in 2014 dollars) in lower electricity costs due to transmission connection would be realized over the 40 year planning period, with such savings likely to continue beyond the planning period. Transmission connection can most optimally be realized by developing radial transmission systems out of supply points at Red Lake, Pickle Lake and / or in the Marathon / Nipigon area. Additionally, uncertainty analysis indicates that for a wide range of probable inputs, transmission connection is expected to cost less than continued supply by diesel generation with over 90 percent probability.

The business case analysis that is the basis of this Plan only accounts for directly avoidable diesel costs and does not reflect the additional economic, societal, developmental and environmental benefits that would arise as a result of connection of these remote communities. Connection would lead to a cleaner electricity supply for these communities as well as reduced environmental risks related to diesel fuel transportation, handling and combustion. Transmission connection would also improve living conditions within the communities by removing barriers to community development. This includes increases to housing stock, expansion of community services and the development /

expansion of local businesses. In addition, these factors are critical to capturing business opportunities as the mining sector expands in northwest Ontario.

The financial benefits of connecting remote communities will accrue to the parties that currently fund their electricity systems, most notably the Government of Canada and Ontario electricity customers. Discussions toward a funding agreement may find a starting point in the notion that connection costs should be attributed to the parties that benefit. Extensive and early engagement among the benefitting parties will be essential to achieving a firm agreement on cost sharing and allocation that will enable this project.

For the four communities that are not economic to connect at this time, renewable resources can reduce cost and environmental impact of electricity supply. OPA will work with each individual community to develop solutions, through community engagement, to reduce dependence on diesel fuel for electricity.

2.0 INTRODUCTION AND BACKGROUND

This Plan describes the Ontario Power Authority's ("OPA") technical recommendations to the Northwest Ontario First Nation Transmission Planning Committee ("Committee") regarding its development of a plan to connect remote First Nation communities in northwest Ontario. The Committee is a collaborative effort between representatives of affected First Nation communities in northwest Ontario, the associated tribal councils, and the OPA. The purpose of the Committee, as stated in its Terms of Reference, is as follows:

> ...to develop a regulatory business case for the expansion of the Ontario electrical transmission system to the remote north. In developing the regulatory business case the Committee, by conferring with the communities, will undertake to capture the diverse needs of the communities and reflect those needs within the technical options for connecting to the provincial transmission system.

This Remote Community Connection Plan is intended to establish at a planning level of certainty the technical and economic viability of connecting remote communities to the Independent Electricity System Operator ("IESO") controlled grid. In developing this Plan, the OPA has sought input from First Nation Committee members and representatives from associated tribal councils, who have contributed their technical and traditional local knowledge as well as the interests of their communities. The OPA has provided the Committee with expertise in power system planning. To ensure that the transmission plan includes facilities required to effectively operate and maintain the system, the OPA also engaged the services of the IESO to conduct an operational feasibility study of community connection. The results of this study have been factored into this Plan.

Members of represented communities have also served as community based researchers, helping the Committee to assess the capabilities and condition of the electrical power systems in their communities and communicate the work of the Committee to interested parties within their communities. These contributions have been integrated into the analysis and the assessment of options that forms the basis of this Plan.

The Government of Ontario stated in its 2013 Long-Term Energy Plan that "connecting remote northwestern First Nation communities is a priority for Ontario." This Plan serves to contribute to the achievement of this priority by supporting discussions between parties that are currently funding electricity supply in these communities as well as supporting the development of projects to connect these communities, which are consistent with this Plan.

This Plan includes a detailed economic analysis, which compares the avoidable cost[8] of continued diesel generation with the cost of transmission connection and supplying electricity to remote communities in northwest Ontario with the provincial generation fleet. This analysis indicates that there is a strong economic case at this time for connecting up to 21 of the 25 remote communities in northwest Ontario to the IESO-controlled grid. The cost of connecting these communities has been assessed to be 30 to 40 percent lower than

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[8] Avoidable costs of diesel operation are the generation related costs, (fuel, variable operations and maintenance, variable overhead, etc.) that can reasonably be expected to be eliminated when an alternate supply source, such as a transmission connection, is used to supply electricity in remote communities.

continuing to serve them using diesel-generated electricity between 2017 and 2054. Over this time period, continuing to operate diesel is expected to cost over $3 billion and transmission connection would cost about $1.9 billion, including capital and operations. Cost savings for benefitting parties are expected to be realized within the first few years of connection. Project breakeven is expected within 20-25 years of project completion. The 20-25 year breakeven period represents less than half the average expected life of transmission and distribution assets such as those proposed to be installed and is therefore considered reasonable for such long-lived assets.

It is important to recognize that business case presented here for transmission connection is based solely upon direct avoidable diesel costs and does not reflect the additional economic, societal, developmental and environmental benefits that would also arise with transmission connection of remote communities. These benefits include, but are not limited to: reduced infrastructure barriers to growth, which may lead to new economic development opportunities (both within the remote communities as well as regionally); improved social and living conditions for remote community residents; cleaner air and reduced greenhouse gas emissions; limiting additional environmental remediation liabilities associated with diesel fuel spills; and the potential for improved reliability of electricity supply in some communities.

For the foreseeable future, expansion of the mining sector is expected to be a major economic driver of the northwest Ontario economy. Mine development may promote economic activity, including job opportunities for these communities. Cost effective access to electricity in close proximity to a potential mine development site is an important consideration for mine project developers in making the decision to invest in a specific property. Therefore, it is expected that once a transmission system connecting the remote communities is available, it may enhance the value of some properties in those areas and lead to new mines being developed. Connection of some new mining loads may be incremental to the load forecast for the area. In return for providing connection to such industrial loads, there is expected to be a requirement for capital contributions from these customers, depending on timing as outlined in Sections 6.3 and 6.5 of the Transmission

System Code. Opportunities of this nature could help to reduce the costs for the funding parties of the transmission connection projects outlined in this Plan.

It should be noted that results of the analysis included in this Plan are based on assumptions regarding the nature of the power system when the report was written. This includes factors such as the availability of capacity on transmission lines and continued operation of existing transmission-connected generation stations in the north of Dryden area. Should the nature of the load, generation or transmission system in northwest Ontario change materially, it may have an impact on the feasibility and costs of the options identified in this report.

The benefits of connecting remote communities to the provincial transmission grid will accrue to the parties that currently fund their electricity systems, most notably the Government of Canada (AANDC), Ontario electricity customers and the Government of Ontario. A substantial near term capital investment will be required in order to realize the long-term benefits of reduced diesel use in remote communities. In order to implement the project, the remote community funding parties, as well as any industrial customers who wish to make use of the transmission assets, will need to come to agreement on the allocation of project costs. A core principle of cost sharing is that costs ought to be borne proportionally to expected benefits. Early engagement among funding parties will be essential to achieving a firm agreement on cost sharing.

It is also important to note that the Far North Act, being implemented by the Ontario Ministry of Natural Resources, requires that all communities conduct land use planning prior to commencing the development of new transmission facilities; thus, the development timelines identified in this Plan may be affected by the progress the communities make in completing their land use plans.

2.1 Background on Electricity Supply in Remote First Nations Communities in Northwest Ontario

There are 27 remote First Nation communities in northwest Ontario with electricity supply.[9] Of these, 25 have electricity generation and distribution systems that are not connected to the provincial transmission grid, with a combined on reserve population of approximately 15,000 people, and peak electricity demand of less than 20 MW. Both population and electricity demand have been growing faster than other regions of Ontario.

The communities are dispersed along an 800 km arc starting from about 90 km north of Red Lake to about 160 km east of Pickle Lake as shown in Figure 10. None of the communities north of Red Lake and Pickle Lake have access to all-season transportation or utility corridors. The average distance separating these communities is about 60 km, with distances ranging between 20 km and 90 km.

These communities are considered remote because most do not have all-season road access and / or they are not connected to the IESO-controlled grid. Electricity service within these communities is supplied by local internal combustion diesel engines driving alternating current (AC) generators, which feed local distribution grids. To date, integrated regional transportation, communication or energy networks have not been developed between many communities. The exceptions are the communities of Armstrong, Collins, and the Whitesand First Nation which are close in proximity and connected to a common diesel generating station located in Armstrong. Recently, many communities were connected via a fiber optic network under a Government of Canada initiative. A number of other communities are connected to one or a few other communities by roads.

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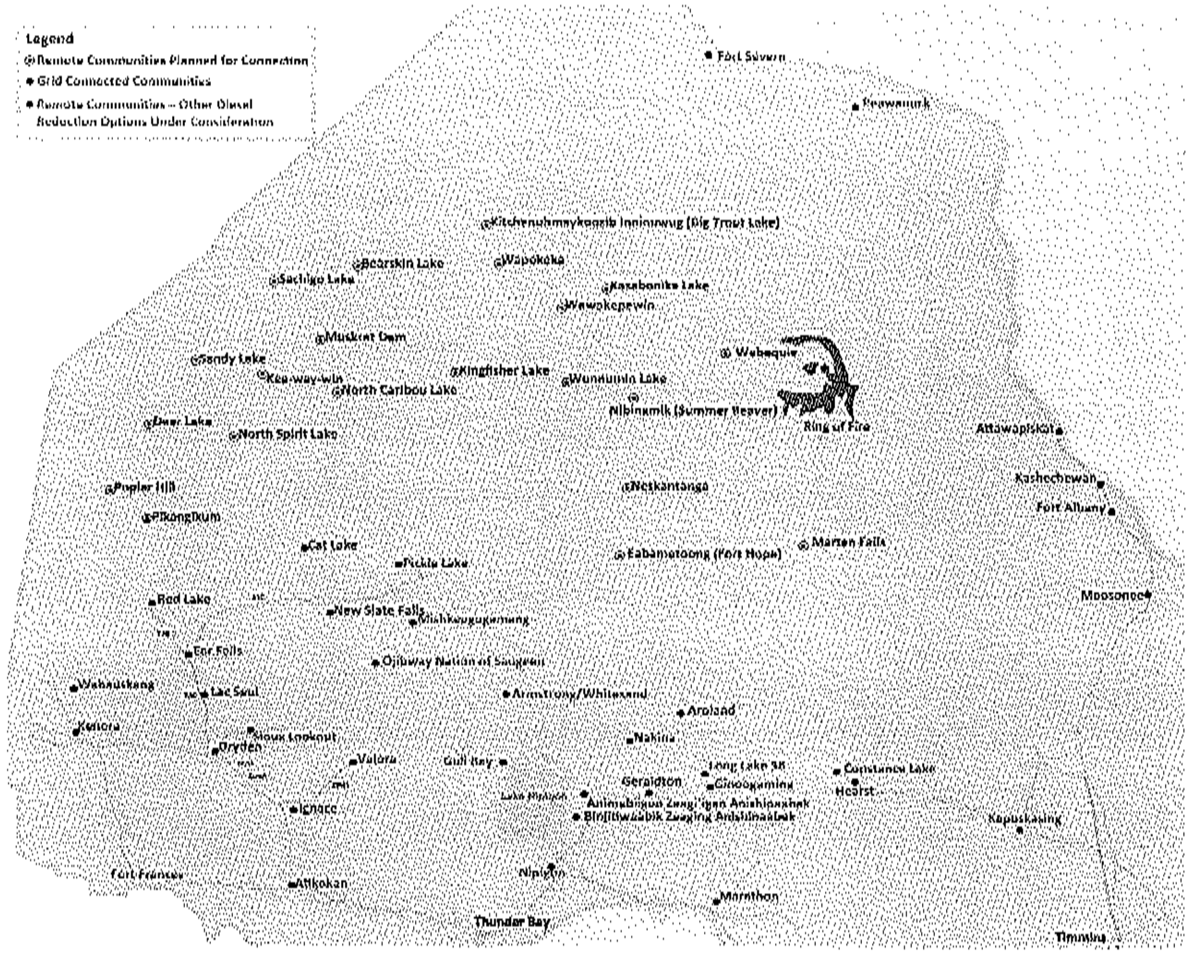
9 The number of remote communities identified differs depending on the source of information. In some cases, neighboring communities are classified as a single community even though residents may self-identify as separate communities. Examples are Keewaywin and Koochiching, which tend to be shown as a single community on Hydro One maps, or the communities of Collins, Armstrong and the Whitesand First Nation. These communities and the First Nation are often shown as a single entity on maps.

Figure 10: Northwest Ontario Remote Communities



Source: OPA

Note: Whitesand First Nation and the Town of Collins are connected to the generating station at Armstrong.

For the majority of these communities, winter roads provide seasonal access for one to two months per year and air transport is the only means to and from the communities for the remainder of the year. This presents a significant challenge in transporting fuel for generation to the communities. Communities utilize local fuel storage (capacity is generally less than a full year), which is replenished when winter road access is available and by air the remainder of the year. Air transport of diesel fuel is significantly more expensive than road transport and therefore has a significant impact on the delivered cost of fuel and the total cost of supplying electricity in communities requiring air transport.

As mentioned above, the electricity systems in these communities are supplied by internal combustion diesel engines coupled to AC generators. In general, these AC generators produce an output voltage of 600 volts, which is then stepped up to the operating voltage of the community distribution system (3.7 kV, 13.6 kV, 25 kV, or other).

Reliability is a critically important factor, particularly in cold weather months, as electric heating is predominant in many communities and lighting is needed due to few daylight hours. Based on this need for reliability, operational flexibility, and efficiency, installed generation capacity of about 235 percent of peak demand, is typically maintained within these communities. Three generation units are generally used and are sized in the ratio 5:3:2. The capacity of the two smallest units establishes the load serving capacity (prime rating) of the system. In comparison, the normal generation reserve requirement for the IESO-controlled grid is less than 20 percent of peak demand.

To accommodate load growth, the diesel systems are expected to be expanded when peak load reaches 85 percent of the prime rated capacity of the system. When system expansion is not provided, new load connections may be refused until new capacity is made available.

In many remote communities, there has historically been a lag between demand for new capacity and the expansion to provide new capacity. Delayed expansion may lead to constrained community growth and pent up demand. Some communities have indicated that their local power systems are currently operating under load restrictions. In affected communities, this can result in new housing and commercial building stock remaining unoccupied and unused for extended periods. There may also be lost economic opportunities when businesses do not form or expand to take advantage of regional opportunities due to insufficient electricity supply or high costs. Constrained electricity supply conditions may also exacerbate residential crowding in these communities, which could increase health and safety risks and impose other costs which are not accounted for in this study.

Growth in mining and other industrial sectors around some of the 21 communities is creating new economic development opportunities. Constrained electricity supply capacity may result in an inability for these communities to provide nearby industries with the goods and services they require in a timely manner. This could result in a loss of opportunity for these communities to participate in the industrial expansion occurring in their areas.

Diesel generation in remote communities is, in general, the highest cost electricity generation resource currently supplying Ontario customers. It costs approximately 3 to 10 times more than the average cost of generation from the provincial supply mix. These high supply costs are due to a number of factors including, the high cost of diesel fuel, which is compounded by the need to transport (by winter road and air) and store the fuel in the communities, as well the higher operating and capital costs of performing construction and maintenance work in these remote locations.

Since 2000, a number of studies have been conducted to assess the viability of connecting remote communities to the provincial IESO-controlled grid. In 2001, Indian and Northern Affairs Canada (now known as Aboriginal Affairs and Northern Development Canada) completed a study of the connection viability of the remote communities in northwest Ontario. In 2009, the Ontario Waterpower Working Group commissioned a similar study of the options for connecting remote communities and high potential hydro resources in the region. Each of these studies concluded that transmission connection of the remote communities north of Red Lake and Pickle Lake is economically viable.

2.2 Current Allocation of Costs for Remote Community Electricity Supply

There are a number of parties involved in providing and funding electricity supply in these remote communities. Aboriginal Affairs and Northern Development Canada ("AANDC") is the department within the Government of Canada responsible for providing and funding infrastructure in all on-reserve First Nation communities in Canada, including electricity supply systems. However, operational responsibilities for 15 communities were transferred to the former Ontario Hydro through electrification agreements. Responsibility for their operation now rests with a subsidiary of Hydro One called Hydro One Remote

Communities Inc. ("H1RCI"). For the remote communities served by H1RCI, AANDC continues to be responsible for funding generation and distribution system expansion associated with load growth in the communities. H1RCI is responsible for operational costs, which include the cost of diesel fuel and maintenance. H1RCI is also responsible for the capital costs for asset replacement due to end of life and improvements that are not associated with load growth. Communities not served by H1RCI are served by First Nation owned Independent Power Authorities ("IPAs"), which are owned by and serve single communities. Among the 25 remote communities, 15 are supplied by H1RCI and 10 are supplied by their own IPAs. The IPAs are not regulated by the Ontario Energy Board. Table 5 details which communities are served by H1RCI and IPAs. AANDC remains fully responsible for maintaining required funding of the electricity supply systems in the IPA-served communities.

Table 5: Remote Northwest First Nation Communities by Electricity Service Provider

Hydro One Remote Communities Inc.	Independent Power Authorities
Bearskin Lake	Eabametoong (Fort Hope)
Deer Lake	Keewaywin
Fort Severn	Muskrat Dam
Kiashke Zaaging Anishinaabek (Gull Bay)	Nibinamik (Summer Beaver)
Kasabonika Lake	North Spirit Lake
Kingfisher Lake	Pikangikum
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	Poplar Hill
Marten Falls	Wawakapewin
Neskantaga (Lansdowne House)	Weenusk (Peawanuck)
Sachigo Lake	Wunnumin Lake
Sandy Lake	
Wapekeka	
Weagamow (North Caribou Lake)	
Webequie	
Whitesand	

As a provincially regulated utility, H1RCI receives a subsidy known as Rural or Remote Rate Protection ("RRRP"), which is funded by all Ontario electricity customers. The RRRP subsidy is used to partially offset the higher cost of providing electricity to rural and remote areas. RRRP is charged to all Ontario electricity customers at the rate of $0.0013, as of May 1, 2014. The RRRP rate is set by the Ontario Energy Board ("OEB").

In 2014, the OEB estimates the total RRRP benefit to be approximately $175.5 M and in 2013 H1RCI was allocated about $33 M of RRRP to fund the 21 remote community electricity systems it serves (including 15 First Nation communities). The six non-First Nation remote communities include the Towns of Collins and Armstrong and a number of remote rail communities in northern Ontario. The balance of RRRP was used to subsidize the rates of other rural customers in Ontario.

Facilities owned by the Government of Canada or the Government of Ontario, such as medical facilities, pay a rate known as the Standard A rate. This rate notionally represents the full cost of electricity service to these facilities. However, Standard A rates have historically been approved by the OEB at a rate that is above cost. The Standard A rate, as well as the regular retail and commercial rates for H1RCI served communities, are set by the OEB through its rate setting mechanisms. The type and amount of rates charged by IPAs vary by community. Some IPAs charge flat rates for service, while others charge by consumption (per kWh); in each case the level of rates charged is believed to vary by community. Communities served by IPAs do not receive RRRP.

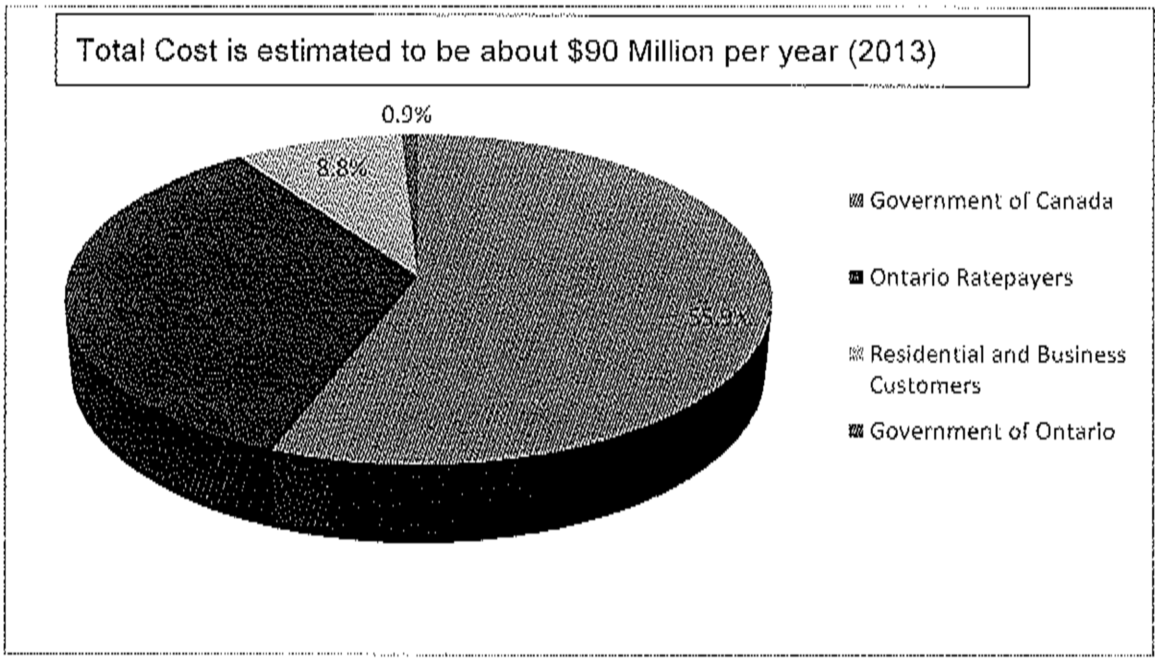
The OPA has limited information to determine the current finances of the IPAs, however it is believed that their relative operating costs are higher than H1RCI's based on the following factors:

- Relative lack of scale in purchasing and operations, as most IPAs have historically operated independently of each other, while H1RCI combines the scale of 15 communities and is able to share some common resources with its parent company.
- Greater sensitivity to diesel price volatility, as IPAs may not procure fuel through long-term supply contracts and may not benefit from volume purchasing and transport to the degree that H1RCI does.

Because detailed cost information for IPA communities is unavailable, the OPA has chosen to use H1RCI's costs (on a per MWh basis) as a proxy for IPA cost for the purposes of this Plan. In discussions between AANDC, the Ontario Ministry of Energy, and OPA, it was agreed that an additional fuel cost of $0.2 per liter will well represent the actual cost differential between IPA and H1RCI, based on the considerations listed above.

Using these assumptions, Figure 11 shows the estimated current allocation of costs between the Government of Canada (AANDC), Ontario electricity rate base, the Government of Ontario and remote community ratepayers (residential / commercial). It is assumed in this cost allocation that AANDC provides funding for IPA costs that are not recovered by rates from customers (Standard A and residential / commercial ratepayers) in those communities.

Figure 11: Estimated Current Share of Annual Cost of Diesel Generation in the 25 Remote Communities by Funding Source



Source: Ontario Ministry of Energy[10]

2.3 Principles for Cost Allocation

A variety of stakeholders stand to benefit from the connection of remote communities in northwest Ontario to the provincial electricity grid. Section 2 showed that the Government of Canada, the Government of Ontario and Ontario electricity ratepayers currently pay about 91 percent of the total cost of electricity service in remote communities.

The economic benefits of grid-connected electricity service in remote communities will accrue to the parties that fund their electricity systems – most notably, the Government of

[10] IPA costs were estimated based on the assumption that they are similar to H1RCI costs per MWh of consumption using values reported in H1RCI's 2013 Cost of Service Application and the Decision and Rate Order. A cost adder of $0.2 per liter was assumed to be the cost difference reflecting inefficiencies associated with IPA diesel systems.

Canada, Ontario electricity customers, and the Government of Ontario. Benefits will not be limited to avoidable diesel generation costs, and will change over time. For example, the need for capital upgrades to the existing diesel generating infrastructure in coming years means that, in the absence of any transmission connection, Government of Canada contributions to electricity service in remote communities will need to increase to levels higher than shown in Section 2. Likewise, increases to contributions will also result from the increasing cost of diesel fuel and its transportation to remote communities.

In addition to these direct economic benefits, the project also affords numerous additional socio-economic, developmental, societal and environmental benefits through such merits as enabling load growth, potentially increasing reliability, reducing environmental impacts and risks, and unlocking economic growth.

Not all of these benefits accrue to each party equally. Table 6 summarizes the main benefits and beneficiaries of the transmission connection project.

Table 6: Beneficiaries of Remote Community and Mining Connections

Beneficiaries	Source of Benefit
Federal Government	• Reduced operating subsidies to IPAs • Reduced diesel system expansion costs • Reduced Standard A rates • Reduced environmental impact and limit the extent of potential future environmental remediation liabilities • Cleaner air and reduced greenhouse gas emissions • Benefits of regional economic development • Reduced societal costs within First Nation communities • Potential to reduce costs for all season road development • Reduced exposure to diesel price volatility
Province of Ontario	
• Ontario electricity customers	• Long-term RRRP subsidy savings
• Government	• Reduced Standard A rates • Cleaner air and reduced greenhouse gas emissions • Benefits of regional economic development

Industrial Electricity Customers	• Avoided diesel generation costs for remote mining facilities and associated liabilities • Opportunity to cost share with remote communities
Remote Community Customers	• Reduced infrastructure barriers to growth • Stabilized retail and commercial rates • Increased economic development opportunities • Reduced environmental impact • Improved reliability of electricity supply • Improved social and living conditions for residents

A substantial near term capital investment will be required in transmission and distribution infrastructure to realize the long-term benefits of reducing diesel use for electricity generation. To ensure a successful project implementation, these investments should come from those who stand to benefit, and should reflect the expected changes in those benefits over time. In order to implement a plan for transmission connection, Government of Canada, the Government of Ontario (representing both the rate base and tax base), the remote communities and any participating industrial customers will need to come to agreement on the extent of costs to be shared and the allocation of those costs among them.

Discussions toward such an agreement may find a starting point in the notion that costs ought to be borne proportionally to benefit -- a principle already contemplated by the existing regulatory framework. However, it is clear that, given the complexity of the project and the diversity of beneficiaries, extensive and early engagement among the negotiating parties will be essential to achieve a firm agreement on cost sharing and allocation. This agreement will also be instrumental for the planning certainty needed to move the project forward in a timely manner. Table 7 below illustrates the core principles which parties could mutually recognize and adopt as a basis for their discussions to help ensure successful outcomes.

Table 7: Principles for Remote Community Connection Cost Sharing

- All parties should acknowledge that, given the current subsidization of remote community energy costs, the feasibility of the transmission connection project is dependent on both federal and provincial financial participation (including the Ontario electricity rate base).
- Project costs should be allocated among the negotiating parties proportionally to the benefits accruing to each.
- Benefits include not only the avoided costs of diesel generation, but also additional benefits such as those relating to the environment and economic development.
- Contributions to project costs should take into account the capital costs, including new transmission and distribution infrastructure and any required transmission infrastructure upgrades, as well as ongoing operating costs.
- Private interests such as mining operations that jointly use some of the project's transmission assets would be expected to pay their proportion of project costs as outlined in the Ontario Energy Board's codes.
- Once grid connected, the total rates charged to remote community residents should remain generally in-line with rates charged to other residents in Ontario. As Ontario electricity customers, residential rates would be set by the OEB in the normal course of its utility rate setting procedures.
- Project costs and benefits accruing to each party should be determined through a transparent process involving the sharing of cost data to make a fair determination of cost sharing responsibilities.

3.0 FUTURE REMOTE COMMUNITY SUPPLY OPTIONS

Transmission connection would lead to a cleaner electricity supply, increased availability of power, improved living conditions and reduced environmental risks related to fuel transportation, handling and combustion. For the purposes of this Plan's comparative quantitative analysis, the business case for transmission connection was developed based on a comparison of the directly avoidable costs of continued operation and expansion of diesel generation required to meet forecast community load growth compared with the cost of connecting the remote communities to, and supplying them from the IESO-controlled grid. Other existing operating costs (distribution system operation and maintenance, customer administration, etc.) will continue to be incurred and are expected to be approximately equal in either case. These costs are therefore not considered avoidable and are not accounted for in this economic evaluation. The costs will, however, remain and must continue to be paid for. There is also expected to be a need for the distribution systems in some communities to be brought into full compliance with standards prior to transmission connection. It is assumed that all electricity systems in Ontario should operate in compliance with Ontario's Electrical Safety Authority's ("ESA") standards regardless of how they are supplied, however it is assumed that IPA communities will require upgrades to reach Hydro One standards.

In addition to the comparison between continued operation of diesel generation versus connecting remote communities to the IESO controlled grid, a high level strategic assessment was also conducted to compare these two alternatives against supplying the remote communities from the existing diesel systems coupled with community based renewable resources.

In conducting the analysis the following general process steps were followed:

1. An estimate of the cost of continuing to supply the 25 remote communities with diesel-fuelled generation over the 40 year planning period was developed.

2. Integrated solutions of conservation, transmission and distribution options were then developed for connecting communities to the provincial electricity grid. These options were developed to ensure the communities could be served in accordance with the supply standards of the province. The options were refined with input from the Independent Electricity System Operator ("IESO") to ensure costs were included for equipment that may be needed to effectively operate and maintain any new portion of the transmission system. The options were also refined with input from the Committee and community members through engagement, to ensure the proposed transmission and distribution line routings were practical and accounted for known community and environmental impacts. Conservation was considered to help relieve interim supply constraints and manage long-term costs for the communities.

3. Supply options for integrating renewable generation with the existing diesel systems in the remote communities were developed on a community-by-community basis. The least-cost scenario (resource type and size) was chosen for comparison with transmission connection and continued diesel supply alternatives.

4. An analysis was also conducted to assess the cost and benefit of supplying subsystems of remote communities using a micro-grid in combination with local hydroelectric power. This alternative was determined not to be cost-effective and was not considered further in the analysis.

5. Financial models were developed to compare different scenarios for supplying the communities.

6. An uncertainty analysis was conducted to understand the relative cost risks of remaining on diesel supply, integrating renewable resources, or connecting to the provincial electricity grid.

7. For the four remote communities that were determined to be uneconomic to connect at this time, an initial assessment of the costs and benefits of displacing diesel generation with local renewable resources and / or a combination of renewable resources and storage was conducted.

Details associated with these process steps are outlined in the following sections.

Based on the overall process outlined above, analysis was conducted to determine the relative cost and technical requirements to connect the 25 remote communities in northwest Ontario that have operating distribution systems powered by diesel generation. This analysis identified that up to 21 of the 25 are economically and technically feasible to connect. As shown in Table 8 below, these 21 communities have an average connection cost of approximately $32,000 per kW-peak in 2034. The four communities that are not economic to connect at this time have connection cost ranging from $50,000 to over $100,000 per kW-peak in 2034. A detailed discussion about these four communities will follow in Section 4.

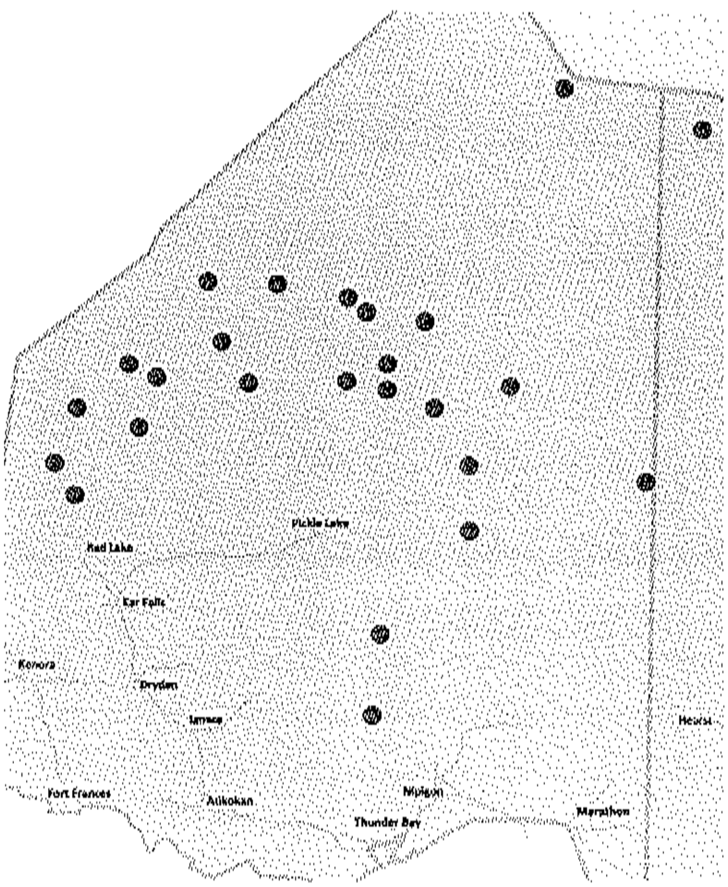
Figure 12 shows these 21 communities (1-21) as well as the four that are not economic to connect at this time (A-D). The remainder of this chapter discusses options for the 21 communities that have been assessed to be economic to connect at this time.

Table 8: Average Community Connection Costs $ per kW-peak in 2033

	Average Community Connection Costs ($/kW)
Average of 21 Communities	$32,000
Zaaging Anishinaabek First Nation	$50,000
Fort Severn and Peawanuk	>$100,000

Source: OPA

Figure 12: Northwest Ontario Remote First Nation Communities



Economic to connect	
1	Pikangikum
2	Poplar Hill
3	Deer Lake
4	North Spirit Lake
5	Sandy Lake
6	Keewaywin
7	Eabametoong (Fort Hope)
8	Neskantaga (Lansdowne House)
9	Webequie
10	Nibinamik (Summer Beaver)
11	North Caribou Lake (Weagamow)
12	Kingfisher Lake
13	Wawakapewin
14	Kasabonika Lake
15	Wapekeka
16	Bearskin Lake
17	Kitchenuhmaykoosib Inninuwug (Big Trout Lake)
18	Sachigo Lake
19	Muskrat dam
20	Wunnumin Lake
21	Marten Falls
Communities not economic to connect at this time	
A	Fort Severn
B	Peawanuck
C	Whitesand
D	Kiashke Zaaging Anishinaabek

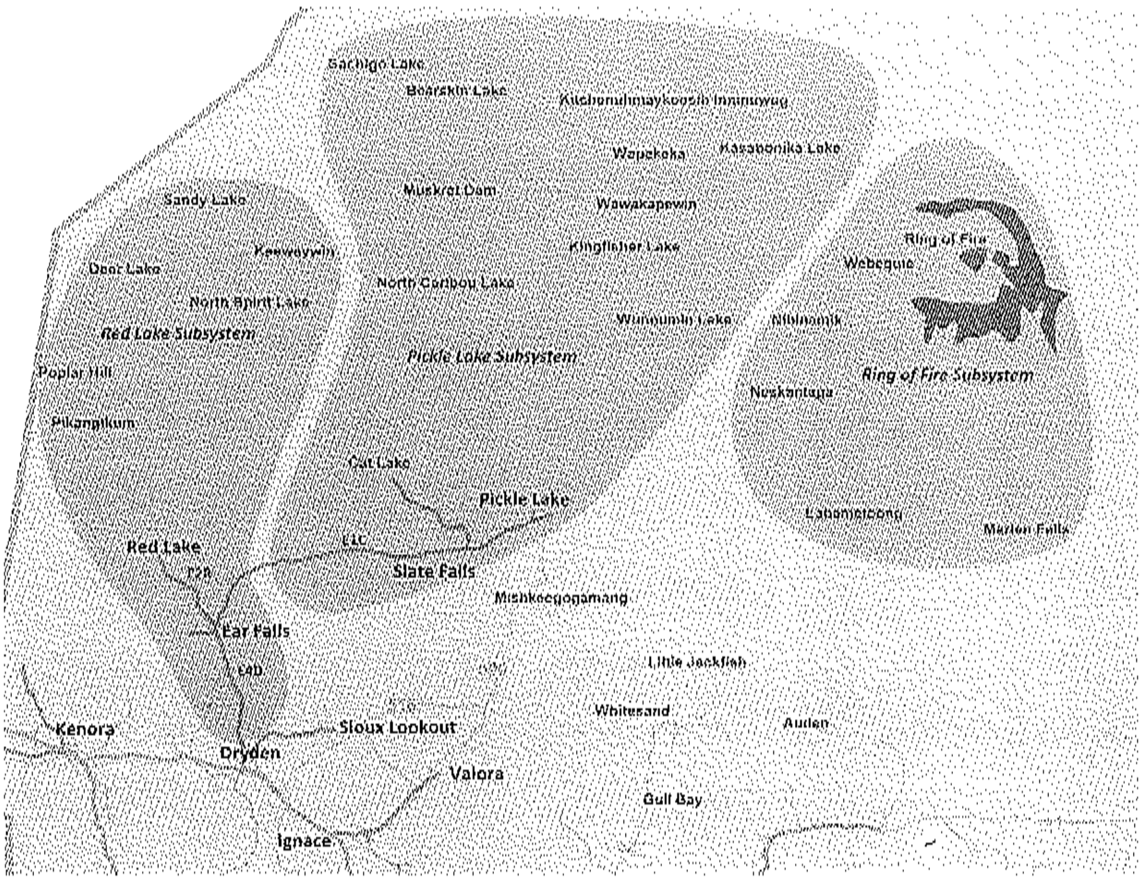
Source: OPA

Process step 2 described above, resulted in grouping the Remote Communities into three subsystems (the Red Lake, Pickle Lake and Ring of Fire subsystems). These subsystems identify Remote Communities which are technically feasible to connect to existing transmission system termination points, while meeting the supply standards established for the Provincial power system. These subsystems are shown in Figure 13 below.

Technical feasibility studies indicate that:

- The Red Lake subsystem can best be served from the transmission system termination point at Red Lake
- The Pickle Lake subsystem can best be served by the transmission system termination point at Pickle Lake
- The Ring of Fire subsystem can be served by the transmission system termination point at either Pickle Lake or from the 230 kV transmission system to the south in the vicinity of Nipigon or Marathon.

Figure 13: Community Subsystems



Source: OPA

3.1 Assumptions and Forecasts Used in the Analysis

Asset Life and Planning Period Duration

Transmission and distribution facilities are long lived assets, which commonly have service lives in excess of 40 years before major refurbishment is required. Some existing facilities in northwest Ontario have been in continuous service for about double this period. For the purpose of this Plan, an outlook or planning period of 40 years (2014 to 2054, which includes 5-7 years of development and construction activities) has been adopted as it represents the minimum expected operating life of a potential transmission and distribution expansion and it provides a reasonable period over which demand and cost factors can be forecast. This period is also expected to be a relevant period over which such long lived infrastructure can be financed.

Inflation

All analysis has been done in real dollars and assumes an average long-term inflation rate of two percent which is consistent with the Bank of Canada's target for the Canadian economy over the long term.

Load and Consumption Growth

Through discussions among Committee members, annual electricity demand growth of four percent for the entire planning period was determined to be reasonable. This level of demand growth is based on the following factors: population growth trends, anticipated intensification of electricity use that is expected to occur in anticipation of and after connection to the IESO controlled grid, and peak electricity demand growth in H1RCI communities between 2010 and 2012 averaging about 3.9 percent. The experience of Five Nations Energy Inc.[11] over the 7 years following connection shows average annual demand growth of approximately five percent. Load growth is assumed to be equivalent under continued supply by diesel, renewable resource integration and transmission connection scenarios.

Given the rate of local economic development expected to materialize as a result of natural resource development opportunities in the area, including at the Ring of Fire, over the next few decades, the OPA and the Committee believe that this level of growth is conservative and likely to be sustained over the long term. Table 9 provides the long-term load forecast for the 25 remote communities in the northwest.

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[11] Five Nations Energy Inc. is a First Nation owned and operated transmission company serving three First Nation communities along James Bay (Forth Albany, Kashechewan and Attawapiskat) from the Hydro One Networks owned system at Moosonee.

Table 9: Forecast Electricity Demand for the 21 Remote Communities in Northwest Ontario

	Forecast Peak Load for 25 Communities				
	2014	2024	2034	2044	2054
Peak Load (MW)	18	27	40	59	87
Energy Consumption (MWh)	82,000	122,000	180,000	267,000	395,000

Source: OPA

Diesel Fuel Price and Unit Energy Cost of Generation

The commodity cost of diesel fuel is based on the bulk purchase price in Thunder Bay. The delivered cost of fuel includes estimated transportation costs to the communities either by winter roads or by air when winter roads are not available. Due to weather and numerous other factors the amount of fuel delivered by winter road and air varies significantly from one year to the next.

In 2013, the eight-month average Thunder Bay rack price excluding tax (commercial rate) for Ultra Low Sulfur diesel was $0.94 per liter. The OPA has used forecast growth rates from the US Energy Information Administration's Annual Energy Outlook Early Release 2013 report to forecast fuel prices in Thunder Bay between 2013 and 2040, which show an expected decline in fuel price between 2013 and 2015 after which moderate growth is expected. After 2040 a real annual growth rate of 1.2 percent is applied, which represents the long run average growth rate in this report. Based on this forecast a commodity cost of $0.89 per liter (in $2014) is assumed for 2017 when communities are expected to begin connecting. The OPA estimates that the average delivered cost of diesel to the communities in the study will increase by more than two-thirds during the planning period between 2014 and 2054.

Due to the location of each community and the availability of winter roads (which offer the lowest cost mode of fuel transport) the volume of fuel delivered by winter road versus air differs widely by community and year. Recently about 70 percent of the generation fuel for all communities has been delivered by air due to warm winter weather and short winter road seasons. Historically it has averaged closer to 50 percent for all of the communities[12]. Climate change is expected to lead to reduced reliability and useful duration of the winter roads in the future. Based on the increase in fuel use and limited availability of winter road system to deliver fuel due to the effects of climate change, it is expected that over the long term the amount of fuel delivered by air will increase as winter road deliveries decrease. The OPA assumes that 30 percent of fuel will be delivered by winter road and 70 percent by air for the entirety of the planning period. However, if the share of air deliveries increases more than forecast, then the delivered cost of fuel will rise above the forecast. Table 10 provides the forecast for the Thunder Bay Diesel Rack Price and the forecast delivered cost of fuel. Through discussions between the OPA, the Ministry of Energy and AANDC, it was agreed that a $0.2 per liter cost adder would be included for IPA communities. This reflects the higher cost due to higher rack rate for smaller fuel purchases and inefficiencies in running local diesel systems.

Table 10: Forecast Thunder Bay Diesel Rack Price (Real Dollars)

	Forecast Diesel Prices				
	2014	2024	2034	2044	2054
Diesel Commodity Price ($/L)	$ 0.85	$ 1.01	$ 1.20	$ 1.41	$ 1.59
Delivered Diesel Price ($/L)	$ 1.49	$ 1.73	$ 2.01	$ 2.32	$ 2.58

Source: OPA

The OPA estimates that the average diesel fuel cost will rise from about $0.45 per kWh for H1RCI communities and $0.51 for IPA communities in 2014, to about $0.78 per kWh for H1RCI communities and $0.84 per kWh for IPA communities in 2054. This rise in unit cost is driven by growth in fuel prices and delivery costs and is shown in Table 11 below.

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[12] Whitesand First Nation and Kiashke Zaaging Anishinaabek First Nation have access to all season roads and thus receive all of their fuel by road. The Hudson Bay communities receive their fuel by fuel barge and air.

Table 11: Forecast Diesel Generation Unit Energy Cost (Real Dollars)

	Forecast Unit Energy Cost				
	2014	2024	2034	2044	2054
Diesel Fuel Cost per kWh	$ 0.45	$ 0.52	$ 0.61	$ 0.70	$ 0.78
IPA Community Cost adder per kWh	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
Variable O&M per kWh	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ 0.17
Diesel Unit Energy Cost IPA ($/kWh)	$ 0.68	$ 0.75	$ 0.84	$ 0.93	$ 1.01
Diesel Unit Energy Cost HORCI ($/kWh)	$ 0.62	$ 0.69	$ 0.78	$ 0.87	$ 0.95

Source: OPA

Ontario Electricity Price

The OPA has forecast Ontario electricity prices for the planning period based on current energy sector plans and policies until 2032. It is assumed that after 2032 prices will grow at about one percent per year in real dollars until the end of the planning period.

Table 12: Forecast Ontario Electricity Cost (Real Dollars)

	Forecast Ontario Electricity Cost				
	2014	2024	2034	2044	2054
Electricity Price ($/kWh)	$ 0.13	$ 0.12	$ 0.11	$ 0.13	$ 0.14

Note: Excludes distribution charges. These charges are assumed to be charged to customers today and would not be incremental to the transmission connection case
Source: OPA

Social Discount Rate

The OPA uses the concept of a Social Discount Rate in its study and planning work. The OPA uses a Real Social Discount Rate (net of inflation) of four percent for economic evaluation of power system electricity-related projects, because it is assessing them in the context of public interest. This rate takes into account infrastructural and environmental aspects with long-term implications for current and future generations. More detail on the

Social Discount Rate can be found in the Integrated Power System Plan 1[13] (as filed with the Ontario Energy Board on August 29, 2007).

Cost to Upgrade Local Systems

It is assumed that all electricity systems in Ontario should operate in compliance with Ontario's Electrical Safety Authority's ("ESA") standards, regardless of how they are supplied, however it is assumed that IPA communities will require upgrades to reach Hydro One standards. The scope and cost of work required to achieve this standard is estimated to be about $750,000[14] per community, depending on the size of the community and the condition of the system.

Diesel Backup

In the case of transmission connection, it is assumed that diesel backup will be required approximately five percent of the time. In the event where transmission lines require maintenance outage, or in the event of a sustained unplanned outage, this diesel backup can be used to meet the needs for critical loads in communities. Estimates of transmission outage time indicate that it is likely that back up diesel of some form will be required less than five percent of the time. Detailed outage estimates can be found in Appendix B.

In the renewable resources options, it is estimated that diesel will be required at least 50 percent of the time. The basis of this assumption is the ability of the system to maintain load following capabilities, and to ensure system reliability.

Financing Transmission Build

The costs of financing assumed in this analysis are that borrowing costs will be incurred during the period of construction, and all debt will be paid in the year the transmission lines

[13] http://www.powerauthority.on.ca/integrated-power-system-plan

[14] This value is an estimate, provided by AANDC, of the average cost for upgrading IPA systems to meet the standard of Hydro One.

go into service. The assumed rate charged for debt is 3.4 percent real. The project is assumed to be debt-financed.

Since the borrowing is assumed to be backed by the government, with commitments from the government of Canada, the government of Ontario and the Ontario ratepayer, the cost of borrowing is assumed at a rate and term similar to that of Hydro One Networks Inc. As the current proponent for the lines to connect remote communities is not Hydro One, there may be differences in actual cost and terms of borrowing. Given that capital costs are approximately $1 billion; this could be on the order of tens of millions per year.

3.2 Transmission Connection

Through a conceptual connection route analysis, the OPA found that radial transmission configurations from Red Lake and Pickle Lake and / or the Nipigon / Marathon area can best connect the groups of communities in the Red Lake, Pickle Lake and Ring of Fire subsystems. This connection arrangement provides the best overall balance of cost, operability and reliability[15]. It is expected that approximately 1,000 km of 115 kV line and 750 km of distribution line will need to be built north of Red Lake, Pickle Lake and / or the Nipigon / Marathon area. Required transformer stations, reactive compensation devices, related switchgear and protection and control systems have been included in these capital estimates.

The base case for the connection of the 21 remote communities is to connect

- the six communities north of Red Lake by a single radial 115 kV line from Red Lake;
- the ten communities north of Pickle Lake by a single radial 115 kV line from Pickle Lake; and

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15 A radial transmission system is one where one or more customers (generators or load) are connected to a single point on an electricity system, which differs from a network system where there are multiple connection points. According to ORTAC, electrical demand levels of up to 150 MW can be supplied from such an arrangement.

- The five communities in the area of the Ring of Fire by a single radial 115 kV line from Pickle Lake that does not connect the Ring of Fire mines.

This base case and other transmission options will be discussed in detail in Chapter 6.

At present the electricity systems serving Pickle Lake and Red Lake do not have sufficient capacity to connect and serve the remote communities. To supply the remote communities within the Pickle Lake subsystem, a new line to Pickle Lake is required. This line must be capable of operating at 115 kV as a minimum, and can be built to either 115 kV or 230 kV standards. The minimum transmission requirement to connect the remote communities in the Red Lake subsystem is to upgrade the existing 115 kV line serving Ear Falls from Dryden (E4D) and the existing 115 kV line serving Red Lake from Ear Falls (E2R) and / or a new line to Pickle Lake[16]. The current demand forecast for the Pickle Lake area indicates that 230 kV supply to Pickle Lake would be required. The transmission options for connection of remote communities assume that the new line to Pickle Lake is built to 230 kV standards.

A proportion[17] of the costs for reinforcing the supply points at Red Lake and Pickle Lake have been accounted for in this Plan as a worst case assumption. Should a portion of these costs, especially for the line to Pickle Lake, be determined to be a network asset, and also have a portion of the cost covered by all Ontario ratepayers, then the cost allocated to the remote communities would be reduced. The proportion of costs attributable to each party was estimated by assuming that each participating customer type (remote communities, industrial customers, etc.) utilizing new capacity will pay a share of the total cost of the

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[16] The new line to Pickle Lake can create some capacity in the Red Lake area (when E1C, the line between Ear Falls and Pickle Lake becomes supplied by the new line to Pickle Lake). The availability of capacity in the Red Lake area following the installation of the new line to Pickle Lake will depend on timing of applications from customers in the Red Lake area.

[17] Proportions will depend on: the demand at the Ring of Fire mines as well as whether the Ring of Fire subsystem is supplied from Pickle Lake. For the case with Ring of Fire mines not connecting, remote communities are allocated 75% of north of Dryden system upgrade and expansion cost. For the case with Ring of Fire at 22 MW peak, supplied by Pickle Lake at 115 kV, remote communities are allocated 35% of north of Dryden system upgrade and expansion cost.

upgrades and expansions required in the north of Dryden system, proportional to their share of the load growth over the 20-year forecast. The OEB's Transmission System Code identifies the principles by which costs for customer connection facilities are to be allocated among multiple parties, which is generally based on proportional use.[18] Cost allocation may also depend on how the system is configured and operated and which customers are willing to participate at the time of construction and financing. Thus it is difficult to determine at this point in time which customers in which locations will contribute to each project and by how much. As mentioned above, this analysis assumes a reasonable worst case allocation of cost.

The draft North of Dryden Integrated Regional Resource Plan[19] (released on August 16th, 2013) describes the supply reinforcement options for the Red Lake and Pickle Lake subsystems that would enable connection of remote communities in those subsystems. It also illustrates the expected demand forecast for the north of Dryden area including the remote communities that are identified for connection. This work for north of Dryden is currently being updated at the time of the release of this draft Plan, and the business case described in this report has assumed the most recent load forecast information for the Red Lake, Pickle Lake and Ring of Fire areas. Cost for upgrades and expansion to the transmission system in the North of Dryden area is based on the remote communities forecast load as of 2033 and the updated low forecast load for the Red Lake area and Pickle Lake area. The low growth forecast is used for the analysis here as it is the most conservative assumption for cost allocation.

The OPA has developed a 20-year load forecast (2013 to 2033) for the north of Dryden area which includes the forecast load for the remote communities assumed to be

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[18] It is recognized that the OEB may consider other allocation models. It is also acknowledged that the parties undertaking the development, construction and ownership of the line projects considered herein, may enter into their own cost sharing arrangements with future customers based on their own needs and interests.

[19] http://powerauthority.on.ca/sites/default/files/planning/North-of-DrydenReportDraft-2013-08-16.pdf

connected in this Plan (15 MW in the Red Lake area, 16 MW in the Pickle Lake area and 7 MW Ring of Fire area in 2033). The forecast used for the Ring of Fire subsystem is dependent on the connection configuration being analyzed for the subsystem; this is because certain configurations are only applicable given medium and high load forecasts for the Ring of Fire mines. The load forecast assumptions used in cost allocation are described in Table 13 below.

Table 13 summarizes the costs that have been estimated for the connection of remote communities and the other participating parties collectively. The "Other Parties" category shown in the table is assumed to include, but is not limited to, direct connected industrial customers, and participating Local Distribution Companies.

Table 13: Total Project Capital Costs and Contributions from Other Parties Sharing Assets

	Transmission Connection without Ring of Fire			Transmission Connection with Ring of Fire		
	Remotes	Other Parties	Total	Remotes	Other Parties	Total
Remote Connection Facilities Only ($M)	1,070	0	1,070	930	0	930
Shared Transmission Facilities ($M)	160	50	210	130	240	370
Total Project Capital Cost	1,230	50	1,280	1,060	240	1,300
Load Growth	38	29	67	38	51	89
Cost per MW Served	32			28		

Source: OPA

The total capital cost for connecting remote communities, including the upgrade of E4D and E2R and the new line to Pickle Lake, is estimated at about $1.2-1.3 billion. The capital cost for transmission and distribution facilities north of Red Lake and Pickle Lake to connect all 21 remote communities, is estimated to be $1.1 – 1.2 billion. The costs are dependent on opportunity for synergy with the Ring of Fire mines as well as fully realized contributions from "Other Parties" to the reinforcements to the existing north of Dryden area.

In addition to the capital cost, operations and maintenance and electricity supply costs must be included to determine the total cost of supplying these communities over the planning period. The total present cost of connecting 21 communities to the provincial grid, including allocated shares of required upgrades to the Red Lake and Pickle Lake areas is shown in Table 14 below. These costs include all ongoing incremental costs for the transmission connection case.

Table 14: Total Cost of Providing Electricity in 21 Remote Communities via Transmission Connection

	Transmission Connection without Ring of Fire ($M)	Transmission Connection with Ring of Fire ($M)
Total Incremental Cost to 2054*	3,350	3,150
PV of Total Incremental Cost to 2054	1,900	1,700
Levelized Annual Cost (2014-2054)	92	83

*Capital costs are net of contributions from other parties expected to utilize the transmission facilities, in accordance with the electricity demand forecast.
Source: OPA

3.3 Continued Diesel Generation

Continuing to supply electricity in the group of 21 remote communities using isolated diesel generation systems would require expanding the existing load serving (prime rated) generation capacity from about 21 MW currently to about 100 MW by 2054. As mentioned in Section 2.0, new capacity is needed when peak load reaches 85 percent of prime rated capacity, or about 18 MW based on existing prime rated generation capacity. Existing peak load in the 21 communities is estimated to be about 18 MW and it is forecast to surpass 20 MW around 2017. New generation capacity is already required in several communities which are operating under load restrictions. It is estimated that as many as half of the communities would be load restricted (i.e. not able to connect new customers) in the next 5-7 years if new capacity is not added. Meeting load growth would entail not only an almost five-fold increase in generation capacity, but also in fuel transportation and storage capacity. If storage capacity is not increased proportionately then the proportion of fuel delivered by air transport will increase above the forecast. This will put the communities at increased risk of not having sufficient onsite reserves during periods when flights may not be possible. Such expansion would involve substantial ongoing financial investment, and would also require substantial new space in each community for fuel storage and new on-site generation units. There would also be an increased environmental impact related to transporting and storing almost five times more fuel than is currently used.

Rising diesel fuel commodity, transportation and storage costs have led to a substantial increase in the unit energy costs recently. As a result, the total cost of supplying the growing demand of remote communities has been increasing as well. Load growth is also driving the need for generation capacity expansion. AANDC estimates that upgrades of diesel system capacity in these communities have cost on average about $15,000 per kW ($2014) of incremental prime rated capacity. For this analysis, the OPA has assumed this average all in cost for diesel capacity expansions, which includes required equipment, storage and integration costs.

Escalating unit energy costs combined with a more than four-fold increase in demand by 2054 plus the high and rising cost of capacity expansion in remote communities is expected to drive the total cost of supplying the 21 communities from a modeled estimate of roughly $60 million in 2014 to nearly $500 million in 2054.

To assess and compare the cost of continued diesel generation with the cost of transmission connection for the group of 21 communities, the OPA identified and forecast the diesel generation costs that could be avoided after the 21 communities are connected to the provincial transmission system. This cost includes:

- Approximately 95 percent of the forecast diesel fuel that would be consumed without a transmission connection (assumes diesel units operate five percent of the time to maintain supply during transmission system outages);
- Avoidable operations and maintenance costs, including long-term cost of generator overhaul and replacement required to operate the expanding fleet; and
- Long-term cost of diesel generation expansion to meet load growth.

Given the potential for planned and unplanned transmission system outages, it is prudent to assume a cost for maintaining diesel capacity currently in operation in the communities for supply security purposes. Currently, there is approximately 38 MW of installed diesel generation capacity in the 20 communities, which if properly maintained, is expected to be sufficient to meet emergency load restoration needs until about 2030. It is assumed that the systems will run approximately five percent of the time to cover emergency and regular maintenance outages. This is consistent with the experience of Five Nations Energy Inc. in operating its system over the past 13 years. Estimates of transmission outage time indicate that back up could be required less than five percent of time. Details on the outage analysis can be found in Appendix B.

The direct costs that are expected to be avoided if diesel generation is replaced by transmission supply in the communities that are economic to connect are summarized in Table 15. Communities are assumed to begin connecting to the IESO controlled grid after 2017, at which time the savings in avoided diesel generation are expected to begin.

Table 15: Avoidable Diesel Generation Costs for the 21 Remote Communities

	Avoidable Diesel Supply Cost ($M)
Nominal Avoidable Cost to 2054	8,300
Present Value Avoidable Cost to 2054	3,100
Levelized Avoidable Cost (2014-2054)	150

Source: OPA

As mentioned previously, complete and accurate costs for the IPAs are not available to the OPA. The best proxy available at the time of writing for IPA operating costs are unit estimates based on H1RCI's rate cases for years up to 2013 and the diesel price and consumption estimates developed by the OPA. Through discussions with AANDC and the Ministry of Energy, an estimate for cost differences between IPA and H1RCI communities was developed of approximately $0.2 per liter higher fuel purchasing and transport price.

Beyond the avoidable economic costs of supplying electricity with diesel in these communities, there are other costs and risks that impact the welfare of the communities and their residents. There are economic aspects associated with these impacts; Lumos Energy has provided a report for Wataynikaneyap Power intended to quantify these aspects. A qualitative assessment of these impacts is discussed in Section 3.5.

3.4 Renewable Generation Integrated with Diesel Generation

A third strategic supply option that was evaluated for supplying remote communities was the utilization of the diesel systems coupled with community based renewable resources. Under this strategic supply option, the existing diesel generators would be integrated with local renewable resources and battery storage to minimize the use of diesel. This investigation considered options for interconnecting communities to larger high potential (hydro-electric) renewable resources without connection to the IESO controlled grid.

Research into other jurisdictions found that renewable generation can be economically integrated with diesel power systems to power remote communities either in regional micro-grids, where distances between communities and generation sites are not great, or as isolated individual community systems. These options could provide some cost and environmental risk reduction over the status quo and they may also create opportunities for more economically developing some renewable energy sites in remote communities.

A high level review of potential renewable generation sites in the area found that the most economic sites are in the order of several megawatts to tens of megawatts in size. Developing a self-standing remote grid requires finding a balance of appropriately sized renewable generation and connected community load. A review of the remote communities in the area and the highest potential renewable energy sites indicates that this balance would be difficult to achieve. For the community electricity systems to remain isolated from the IESO controlled grid, development of the larger scale, more economic renewable sites would require the pooled demand of at least 3-5 communities. However, this would require hundreds of kilometers of transmission and distribution line be built to connect the generation with sufficient load. This requirement adversely affects the overall economics of such projects.

Further, in all cases diesel generation would still be needed to meet demand when variable renewable resources are insufficient or unavailable, such as when run-of-river hydro sites have insufficient flow to meet demand or wind is not available. It is expected that even with efficiently sized renewable generation the community diesel generation units would need to provide at least 15 percent of the energy requirements in each community. While battery storage can eliminate some inefficient diesel operation (low load operation below the engine's optimal efficiency level), the technology is costly and the diesel units would need to run regularly to meet demand variations and maintain operability of the local system. This inefficient operation would limit the amount of diesel fuel that could be offset. As a result, it is expected that the long-term cost of renewable resources integrated with diesels in either micro-grids or isolated systems will remain high because of:

- Substantial new investments in generation and transmission infrastructure (for the micro-grid option);
- Limited reduction in diesel consumption; and
- Cost of installing battery storage technology to achieve efficiencies.

Table 16 shows the average energy costs for relevant sub-sets of the 25 remote communities considered in the analysis of each technology and compares them to the status quo option of continued diesel operation.

Table 16: Comparative Average Total Cost of Electricity Supply For Alternative Supply Technologies

	Average Total Cost of Supply to 2054 ($/kWh)		
	Low	High	Remaining on Diesel Supply
Diesel Generation	1.10	1.20	All
Isolated Wind Integrated with Diesel	0.85	0.95	All
Isolated Solar Integrated with Diesel	1.10	1.20	All
Isolated Wind and Solar Integrated with Diesel	0.85	0.95	All
Hydro Connected to Community Clusters	1.10	1.50	>10
Transmission Connection	0.40	0.50	<=5

Source: OPA

The OPA has found it is not as economic for communities to be served economically by renewable generation integrated with diesel relative to transmission connection, due to large variances of resource availability. This finding does not preclude the prospect of integrating renewable resources following connection of the communities to the IESO-controlled grid. Opportunities for connecting renewable generation in northwest Ontario can be assessed during more advanced stages of transmission planning work, when Ontario will be better able to consider project proposals in the context of broader electricity resource planning at the provincial level. This includes consideration of Ontario electricity demand and cost-effectiveness of supply options, as well as relevant procurement targets and programs at the time.

3.5 Option Comparison: Benefits of Connecting the 21 Remote Communities

In the long term, transmission connection is the more economic of the options assessed. In communities that are not currently economic to connect, renewable generation can help to lower costly diesel consumption. As is discussed further in Chapter 4, options for adopting renewable power systems in these communities should be investigated.

Cost Benefits

Based on the economic analysis shown in Table 17, the average cost over 40 years of connecting the 21 remote communities to the IESO controlled grid is expected to be $55 million to $65 million per year less than continued diesel operation. Table 17 compares the avoidable cost of diesel generation with the cost of connecting and supplying power to the communities from the IESO controlled grid or by integrated renewable resources with the existing diesel systems.

Table 17: Net Present Value of Electricity Supply to Remote Communities Over the First 40 years

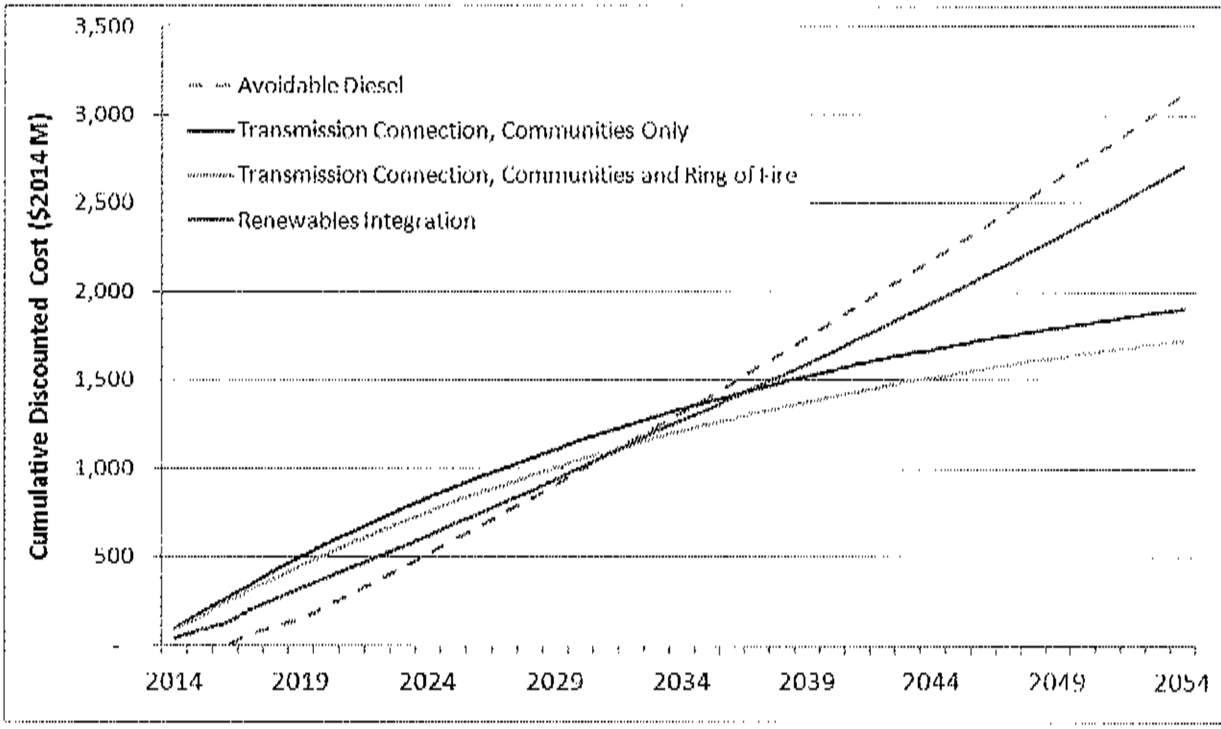
	Alternatives		
	Remotes Transmission Connection Only	Remotes Transmission Connection with Ring of Fire	Integrated Renewable Generation
Avoided Diesel Present Cost ($M)	$3,120	$3,120	$3,120
Alternative Present Cost ($M)	$1,900	$1,750	$2,600
NPV ($M)	$1,220	$1,370	$520

Source: OPA

Based on the direct avoidable costs assessed, transmission connection a favourable net present value relative to the avoidable cost of diesel. The project is expected to break-even 20-25 years after all of the communities are connected as shown in Figure 14 below. Figure

14 shows the cumulative costs, and breakeven point for all alternatives. Over a 40 year period, transmission connection could supply the remote communities at less than 70 percent of the cost of continued diesel generation. Figure 14 provides a graphical representation of these two points by showing the cumulative cost of avoidable diesel generation versus the cost of supplying the communities by transmission connection. Transmission assets typically last much longer than the 40 year period used in this analysis, and will thus continue to provide value for many years beyond. The cost of continuing to supply these communities by transmission after 2054 (once the assets are fully paid for) is very attractive as typically only the operating and maintenance costs of the transmission facilities will remain, whereas the full and rising cost of diesel expansion and operation would need to be covered in the status quo option.

Figure 14: Cost of Transmission Connection versus Cost of Avoidable Diesel Generation



Source: OPA[20]

As noted previously, the assessment shown in Figure 14 is conservative insofar as it does not quantify economic, societal, developmental and environmental benefits of transmission connection beyond avoided diesel costs. These additional benefits include reduced infrastructure barriers to growth, increased economic development opportunities (both within the remote communities as well as regionally), improved social and living conditions for remote community residents, cleaner air and reduced greenhouse gas emissions, reduced future environmental remediation liabilities associated with diesel fuel spills, and potential for improved reliability of electricity supply. While the focus on direct costs of

[20] The transmission costs have been amortized over a 45-year period, reflecting the minimum expected life of transmission assets. This affects the breakeven time by one to two years; however, analysis indicates that breakeven would occur in 20 to 25 years, regardless of this financing assumption.

avoidable diesel in this analysis helps ensure a conservative assessment of the business case, decisions to invest in the project should also incorporate these additional expected benefits into the rationale for proceeding with the project, many of which are very relevant to communities and the entities responsible for these operating costs. Some benefits have been quantified through estimates of concepts such as avoidable environmental contamination liabilities, or the value of economic activity and foundational infrastructure in remote First Nations communities. These are discussed later in this Chapter.

There may also be future opportunities for excess available capacity in the proposed transmission facilities to be used by industrial customers or generation projects. Industrial and resource operations that may have been previously uneconomic to develop due to the high cost of diesel generation may be economic once reliable and relatively low cost power is available nearby through a transmission connection. Should these potential loads choose to connect they would be required to contribute to the cost of the projects in this Plan, which could further reduce cost and long-term risk associated with the project. This opportunity is not available with the existing diesel generation available in the remote communities.

Having grid access may also improve the economics of generation projects that may be desirable to develop in the future. There are also a number of potential hydroelectric sites in the area, which range in potential size up to about 30 MW. These sites could be developed at a larger scale and thus be more economic to develop if transmission is available in the area. With available grid connection, these projects could sell power generation to the provincial grid, providing a revenue source for communities. Generation in this area could also provide incremental load serving capacity to the area, by providing energy, capacity and reactive power locally. Developing these sites may also reduce the need for transmission equipment that might otherwise be needed to maintain voltage and stabilize the system. The future development of new hydro projects in northwest Ontario would be subject to a separate decision process and is not considered further in this Plan.

The current funding parties (the Government of Canada (AANDC), the Ontario provincial rate base, the Ontario provincial tax base, and ratepayers in the communities) are the direct benefitting entities associated with connecting the identified communities to the IESO controlled grid. It is expected that costs related to connection would be shared among these benefitting parties in proportion to the benefits each would receive. Industrial customers would also be expected to contribute to the cost of the project in proportion to the load they connect to the facilities.

Mitigating Uncertainty

To determine the degree to which the findings within this analysis are robust, the OPA conducted an uncertainty analysis using a Monte Carlo simulation tool. This analysis provides a statistical representation of the net present value of the business case over a wide range of assumptions for several key variables which have been found to drive the outcomes. These variables are detailed in the following table.

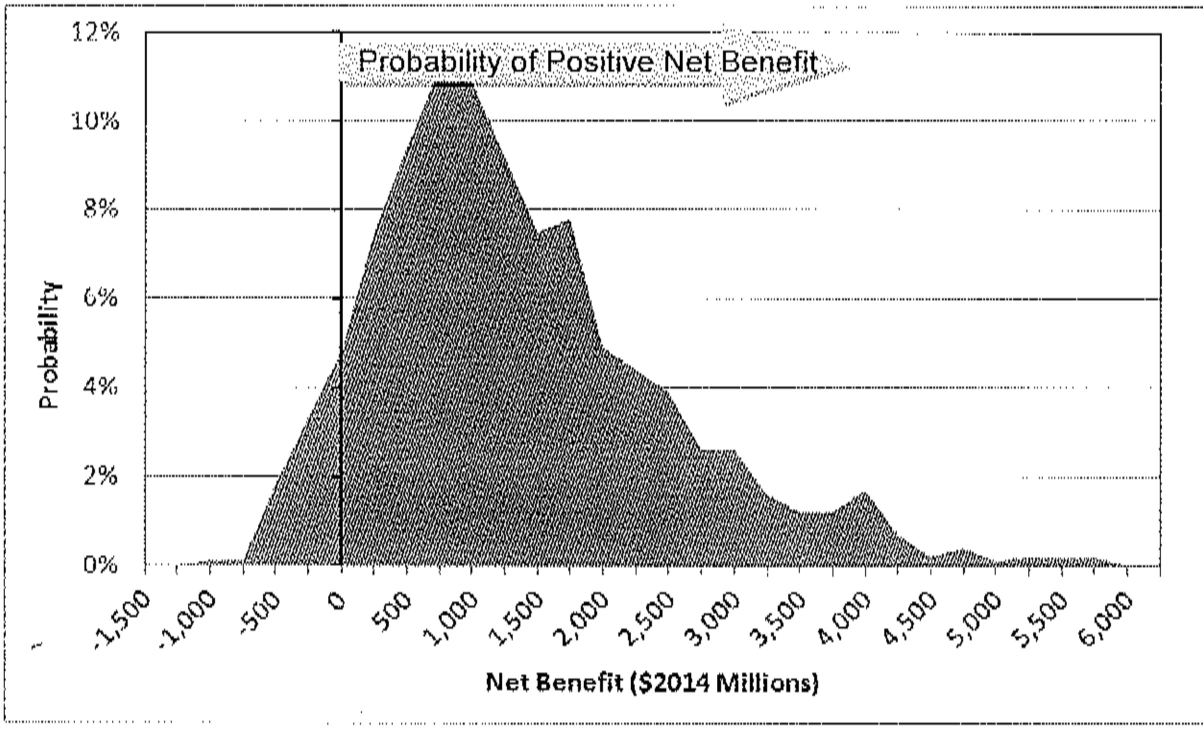
Table 18: Key Variables for Uncertainty Analysis

Variable	Average	Distibution Type	90% Interval
Demand Growth	4%	Normal	+/- 4%
Diesel Price Growth	1.20%	Normal	+/- 1%
Transmission Cost	0%	Normal	+/-50%
Renewables Cost	0%	Normal	+/- 20%

Note: The variable used for diesel price growth modifies the annual growth assumption relative to the EIA fuel price forecast used. The transmission variable modifies the assumed cost unit cost for transmission and distribution facilities. The renewable resources variable modifies the assumed cost per kW for new renewable facilities and controls.
Source: OPA

The distribution of the Net Present Value of transmission connection compared to continued diesel use is summarized in Figure 15. These findings indicate that under a wide range of inputs and probability assumptions the project net present cost for transmission is expected to be less than continued diesel. While there is a less than 10 percent probability that transmission connection could be marginally higher cost than the continued diesel case, the probability of the diesel case being substantially higher than the cost of transmission connection over the same 40 year period is roughly three times higher. This finding is a strong indicator of the probability of net economic benefits materializing by 2054.

Figure 15: Net Present Value Distribution of Base Case (Communities Only)



Note: this chart does not include the renewable resources case as the net benefit results are concentrated in the small range of $0M - $500M (98 percent of results) due to the alternative being highly correlated with the avoidable diesel case. Displaying all alternatives would skew the scale of the graphic.

Source: OPA

Transmission connection provides a natural hedge against the upside risk associated with the diesel case by fixing the largest part of the project's lifetime service cost (capital) at the time of construction. In addition, it should be recalled that actual IPA diesel service costs are expected to be higher than estimated in the OPA's analysis, such that the probability of a positive NPV for the transmission case should be higher than this analysis predicts.

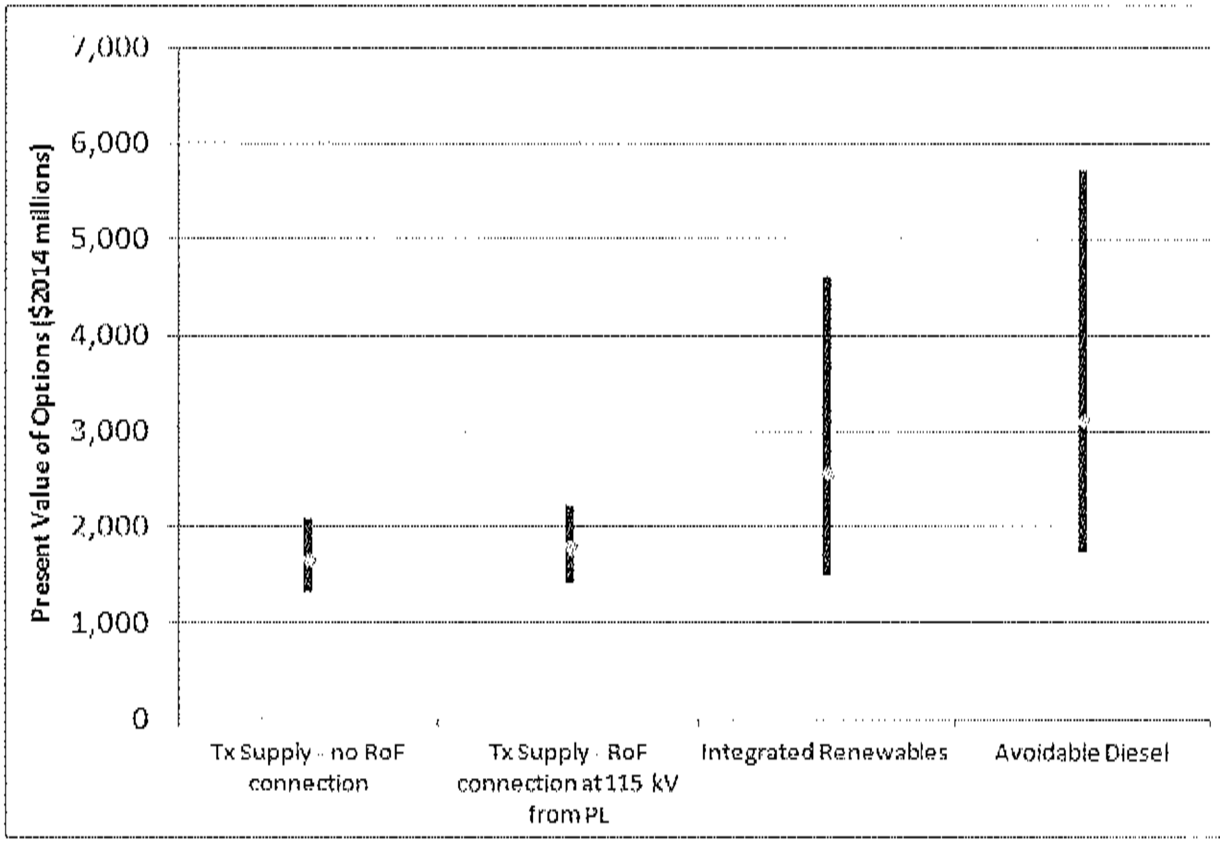
The analysis indicates that over a 40 year planning period (2014 to 2054), the transmission connection base case has an expected NPV, relative to continued diesel, of over $1 billion and there is a greater than 90 percent probability of a positive NPV[21] over that period.

The analysis also looked at the contribution of each variable to the observed uncertainty in the simulations. Demand growth is the overriding driver of variation for all three options. The uncertainty in the integrated renewable resources case is similar to that of the diesel case, given that diesel would continue to be the dependent supply source. Demand growth is also the main driver of the amount of difference in uncertainty between the diesel generation case and the transmission connection cases. This is because, in the diesel generation and integrated renewable resources cases, demand growth plays a large role as this variable is compounded over the period and acts directly on the cost of fuel consumed (the price of which is also compounded over time) and on the generation expansion costs which are also rising. Comparatively, the transmission connection cases are characterized by mostly fixed costs that are set when the project is built. The only major factor influenced by demand growth is the cost of power consumed, which is a relatively small cost in this case. More detail on the range of independent variation for each variable is shown in Appendix A.

It is clear that the risk factors weigh more heavily against the continued use of diesel, rather than to the transmission case. Figure 16 illustrates the risk or potential variability associated with the electricity supply options.

[21] Positive NPV means the cost of status quo is greater than the alternative cost of transmission connection for the 21 communities.

Figure 16: 90 Percent Confidence Interval of Alternatives



Source: OPA

1 More detail on the methodology and results of the uncertainty analysis is provided in Appendix A.

3 Societal and Environmental Benefits

4 The economic analysis presented in this Plan does not include the potentially significant additional economic, societal, developmental and environmental benefits to be derived from transmission connection of remote communities. A study commissioned by Wataynikaneyap Power which was prepared by Lumos Energy[22], indicates that $1 billion to

[22] Project Benefits Study - Social, Environmental and Economic Analysis: Wataynikaneyap Power Project; Lumos Energy, June 2013

$4 billion in additional benefits may be created by connection of 10 remote communities in the Pickle Lake subsystem. Applying this estimate to all remote communities that can be connected is expected to derive even greater economic and other benefits which have not been accounted for by the economic analysis undertaken in this Plan.

The societal benefits of connecting remote communities to the transmission system are reduced health risk, improved quality of life, improved community infrastructure, improved power quality and regional employment and skills development.

Reduced use of diesel for electricity generation will also have significant effects on the environmental impact of power generation in the communities. It will improve environmental quality within the communities by limiting diesel fuel spills, pollution resulting from combustion and noise pollution of the diesel system. Diesel generation creates significant emissions in remote communities, causing local pollution and greenhouse gas releases. Based on standard estimations of greenhouse gas emissions from diesel combustion, it is estimated that at current generation levels approximately 65 kT of GHGe emissions are produced annually. Continued use of diesel generation will lead to rising annual emissions resulting in over 6 MT of avoidable incremental GHG emissions compared to supplying the communities from the Ontario generation mix over the next 40 years. Reducing or eliminating diesel combustion is expected to improve air quality and noise pollution in the communities.

There will also be improvement in environmental impacts beyond the community by limiting transport of diesel. These communities rely on air transport 70 percent of the time and road 30 percent of the time. This transport alone results in environmental impacts due to pollution.

Pricing of carbon emissions have also not been included due to uncertainty over when / if a carbon pricing mechanism will be implemented and if one is implemented what price might be applied to diesel emissions. This results in an additional degree of conservatism within the overall analysis.

4.0 PLAN FOR REMOTE COMMUNITIES IDENTIFIED AS NOT ECONOMIC TO CONNECT AT THIS TIME

As noted in the previous section, four remote communities have been identified as uneconomic to connect at this time: Whitesand, Kiashke Zaaging Anishinaabek (also known as Gull Bay), Fort Severn and Peawanuk (Weenusk).

A preliminary, generic analysis conducted for these communities indicates that displacing diesel with renewable resources, especially small-scale wind generation, can be an economic option. However, detailed studies for each of the four communities will be required to determine specific solutions. In a directive dated December 16, 2013, the Minister of Energy instructed the OPA to "work with those remote First Nation communities where transmission connection is not identified as economic in the OPA's plans and other appropriate parties, in order to develop and implement solutions for on-site renewable generation that reduce their dependency on diesel fuel." The directive requires the OPA to complete plans for these four communities by the end of 2014. As of summer 2014, the development of these plans was underway.

In developing these plans, the OPA will work closely with these communities to identify their unique and individual needs and preferences. The process will account for any Community Energy Plans or Economic Development Plans that the community already has developed or is under development. Plan development will require an assessment of current electricity consumption trends in the community, an assessment of current diesel costs, and an evaluation of alternatives that will assist in cost effectively reducing diesel consumption. The OPA will continue to support community meetings and planning sessions, as well as collecting, presenting and processing baseline information required to proceed with this planning work. Options assessed within this process include, but are not limited to, conservation, renewable micro-generation projects, and other innovative options such as storage technologies.

There are three main factors that make the 21 communities economic to connect to the IESO controlled grid:

- Communities are arranged in natural geographic subsystems that allow efficient routing of transmission and distribution lines to connect them;
- Communities within each subsystem are relatively close to each other;
- The largest communities having the highest electricity consumption tend to be the greatest distance from the existing grid. The high diesel based electricity consumption makes it economic to extend transmission to these distant communities. Since the transmission line route to these large communities passes by a number of the smaller communities, they in turn become economic to connect.

The primary reasons identified in the evaluation that make the remaining four communities uneconomic to connect at this time are their distance from the IESO controlled grid and their relatively small electrical demand. Some of them may become economic to connect in the future if their electricity demand grows or if other opportunities materialize which enable a sharing of costs, such as development of industrial loads or generation projects in the area.

In the case of Whitesand First Nation and Kiashke Zaaging Anishinaabek First Nation, the most likely grid connection would be via a dedicated line from the transmission system south of Lake Nipigon. At this time, a line from the existing line in the Nipigon area, A4L, to these communities is not a cost effective option. If the connection of the five communities in the Ring of Fire subsystem is pursued through routing in the Nipigon area, opportunity for connection of these communities could be revisited. The higher cost per kilowatt to connect Whitesand First Nation and Kiashke Zaaging Anishinaabek First Nation is due to their small load relative to the long line length required to accomplish the grid connection. As the load in these two communities grows in the future, the economics of grid connection may improve[23].

As mentioned above, preliminary analysis revealed that displacing diesel with renewable resources, especially small-scale wind generation, can be economic. It is important to note

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[23] It is relatively easier and lower cost on a per kilometer basis to build line to serve communities with all season road access than those in the remote far north; however the avoidable diesel costs included in a business case to connect these communities is also much lower because the transport cost is reduced.

that these studies indicate that maintaining a reliable electrical supply source to these four communities will require maintaining diesel generation as the primary supply source. Renewable resources, especially wind and solar, are generally intermittent in nature, and their operating profiles do not match well with community demand needs.

Table 19 through Table 21 provide the results of a preliminary cost benefit analysis, which shows that the cost of integrating renewable generation and storage with existing diesel systems is likely to be more cost effective than continuing to operate solely with diesel generation. The energy costs provided in these tables are the total installed capacity for next 40 years and the average unit energy cost, including the maintenance and operation of the existing diesel system.[24] The analysis shown in these tables found that the resource combinations of wind / diesel are the most cost effective and provide the greatest reduction in diesel consumption. There would also be environmental advantages to making this change, which are not captured in this preliminary cost benefit analysis below.

[24] The cost for continued operation and maintenance of the diesel system are included to the same extent as demonstrated for the 21 communities that are economic to connect at this time. Cost to maintain and operate the local community distribution system is not included.

Table 19: Economic Renewable Supply Cases for Wind, Solar and Storage

	Wind Capacity (kW)	Solar Capacity (kW)	Storage Capacity (kWh)	Energy Supplied by Diesel	Energy Cost ($/kWh)
Fort Severn	600	100	200	51%	0.91
Peawanuck	300	100	100	55%	1.01
Whitesand	1200	100	400	52%	0.93
Kiashke Zaaging Anishinaabek	400	50	200	60%	0.93

Table 20: Economic Renewable Supply Cases for Wind and Storage

	Wind Capacity (kW)	Storage Capacity (kWh)	Energy Supplied by Diesel	Energy Cost ($/kWh)
Fort Severn	600	0	53%	0.90
Peawanuck	350	0	50%	0.97
Whitesand	1300	0	50%	0.91
Kiashke Zaaging Anishinaabek	350	0	54%	0.93

Table 21: Economic Renewable Supply Cases for Solar and Storage

	Solar Capacity (kW)	Storage Capacity (kWh)	Energy Supplied by Diesel	Energy Cost ($/kWh)
Fort Severn	300	0	92%	1.11
Peawanuck	200	0	90%	1.16
Whitesand	800	0	90%	1.10
Kiashke Zaaging Anishinaabek	100	0	95%	1.11

Source: OPA

It should be noted that the unique opportunities and resources available in each community as well as preferences of community members, will determine the solution that will best fit a particular community's electricity needs. The OPA will continue to work with these communities identify their unique and individual needs, help the communities develop solutions that will assist in cost effectively reducing diesel consumption and develop plans for each community by the end of 2014.

5.0 CONSERVATION FOR REMOTE COMMUNITIES

5.1 Introduction

Conservation can be the cleanest and least costly resource for meeting electricity needs. It allows consumers to better manage their electricity consumption and bills while at the same time helping to avoid investments in new electricity infrastructure. As a result, the government of Ontario has made conservation a priority in the province and has committed to expanding and enhancing the province's conservation efforts.[25,26]

5.2 Value of Conservation in Remote Communities

Conservation provides a number of benefits to remote communities. Communities economic to connect to the grid can benefit from conservation in the time leading up to connection and these communities would continue to benefit after connection as well. Communities which are uneconomic to connect are likely to experience the highest benefits due to the high cost of relying primarily on diesel fuel. These benefits include:

- Enabling community growth by reducing existing demand and freeing capacity on the electricity micro-grid
- Helping community members to manage their electricity costs
- Leveraging conservation programs to improve the quality of building stock located in these communities
- Creating local jobs in the conservation sector

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[25] Conservation First: A Renewed Vision for Energy Conservation in Ontario. http://www.energy.gov.on.ca/en/conservation-first/#.U8UtVJ3D_RY

[26] 2015-2020 Conservation First Framework Directive to the OPA from Ministry of Energy. http://www.powerauthority.on.ca/sites/default/files/news/MC-2014-856.pdf

Remote communities are currently supplied by diesel systems of finite size and micro grids with limited distribution capacity. The ability of remote communities to grow (population growth and economic activity) is currently impacted by the limits of these micro-grids. Conservation could be used to manage these constraints by reducing existing demand to allow for growth without the need to expand diesel systems. It can also be used as a bridging resource while communities await grid connection.

Conservation can also play a valuable role in helping community members and businesses manage energy costs. This is especially important after connection to the grid. A trend that has been observed in other Fist Nation communities in Ontario after grid connection is a growth in energy consumption driven by the increased installation of electric baseboard heaters and electric stoves.

Conservation programs often involve installation of insulation and new windows. Such measures can improve the quality of living in buildings. This can be particularly beneficial when aligned with other programs targeting building upgrades.

In addition to the above benefits, conservation programs for remote communities can also create job opportunities for local First Nations. Opportunities may exist to build local capacity for program design, delivery, and implementation through education and training.

5.3 Current Suite of Programs Offered to Remote Communities

At present, the following conservation related programs are available to remote communities:

- Aboriginal Conservation Program
- Aboriginal Community Energy Plan

The Aboriginal Conservation Program (ACP) provides customized conservation services designed to help First Nation communities reduce their electricity use in residential housing and in commercial and institutional buildings (e.g. stores, schools and band offices). The program also creates employment opportunities, potentially providing up to 30 jobs in selected First Nation communities. Program managers, community coordinators, canvassers and energy auditors have been hired to deliver the program to participating communities.

Residents in communities participating in the ACP Program have an opportunity to work with a certified energy auditor, who recommends electricity-saving measures based on an assessment of their homes. These measures can include:

- ENERGY STAR® CFL light bulbs;
- Smart power bars;
- Hot water tank wrap and pipe insulation;
- Efficient showerheads and faucet aerators;
- Block heater timers, programmable thermostats; and
- Attic, wall and basement insulation.

Eligible businesses and facilities can receive assessments for their lighting and water-heating systems as part of the program, up to $1,500 in energy-efficient lighting and equipment upgrades, and gain access to further incentives.

By the end of 2015, 5 of the 25 remote communities in northwestern Ontario that are not grid-connected will have received conservation measures through the Aboriginal Conservation Program. In the first year of the Aboriginal Conservation Program, 12 First Nation communities, including 2 remote communities, were selected to implement conservation measures to meet their energy needs. In its second year, an additional 17 First Nation communities, including 3 remote communities, were selected.

The Aboriginal Community Energy Plan (ACEP) program is designed to assist First Nations and Métis Communities in developing a community energy plan or to update an existing community energy plan. A community energy plan is a comprehensive long-term plan to improve energy efficiency, reduce electricity consumption and assess opportunities for green energy solutions. The ACEP program supports First Nations and Métis Communities in determining local interests, prioritizing unique needs and opportunities for conservation and small-scale renewable generation projects. It is anticipated that the ACEP Program will re-open in the fall, 2014.[27]

5.4 Implementation of Programs for Communities in Preparation for Connection

The OPA is currently working on a new six year Conservation First Framework. As part of this framework, the OPA will look specifically at the unique needs for conservation in remote communities today and in preparation for connection. In addition to this and to maximize conservation in remote communities the OPA recommends the following:

- Continue to make ACEP funding available to all remote communities to allow them to become actively involved in energy planning while helping communities to better understand their electricity consumption patterns. In the near-term, this would help communities find strategic conservation initiatives to ease constraints related to limited micro-grid capacity. As part of this, a conservation achievable potential study could help remote communities better understand energy savings opportunities. Over the longer term, an energy plan can also serve as a starting point for understanding which renewable technologies might benefit the community.
- Seek to integrate identified conservation measures with other services being provided to communities. For example, housing services in communities that build new homes could use this as an opportunity to create more energy efficient homes that utilize higher standards of efficiency and provide for weatherization. Those providing these services could take into account the energy needs of the communities including the existing community growth limitations and future energy costs.

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[27] Please see the ACEP Program web-site at: http://aboriginalenergy.ca/aboriginal-community-energy-plans for program updates.

6.0 CONNECTION PLAN FOR THE 21 REMOTE COMMUNITIES

The practical development of a staged connection plan must account for the geographic relationship between available supply points (Red Lake, Pickle Lake and / or the Nipigon area) and the various communities, the long-term load levels to be served as well as environmental challenges and land use constraints. This Plan envisions line development being implemented in stages starting from Red Lake, Pickle Lake and / or the Nipigon area and moving north. As a transmission backbone is developed, transformer stations and distribution feeders are assumed to be constructed to connect adjacent communities in the area. This allows for communities to be connected as transmission development progresses north along proposed corridors to the various communities.

The OPA, in consultation with the Committee, has considered and assessed a number of routing and line configuration options previously studied by Indian and Northern Affairs Canada (2001), the Waterpower Working Group (2009), and the Central Corridor Energy Group. This Plan leverages many of the same principles employed in those previous studies, while improving the balance between cost, reliability and operability, through the use of strategically located transformer stations and distribution facilities.

The connection options identified in this Plan have attempted to satisfy and balance the following criteria:

- Feasibility, the ability to meet long-term electricity demand growth while meeting relevant technical criteria;
- Meeting the requirements of the Ontario Resource and Transmission Assessment Criteria ("ORTAC");
- Cost;
- Security and reliability of supply;
- Flexibility, including consideration of connecting future renewable generation sites and potential commercial / industrial customers that enhance economic opportunities;
- Environmental Performance; and
- Societal Acceptance.

6.1 Connection Configuration Options

The OPA has considered and assessed both radial and interconnected line configurations to connect the communities. This assessment concluded that radial systems can be economically justified, while meeting the system performance requirements specified by the IESO. It should also be noted that the IESO's Ontario Resource and Transmission Assessment Criteria (Section 7.1 Load Security Criteria), allows for loads up to 150 MW to be served by single circuit radial lines.

The OPA has investigated the technical and economic feasibility of an interconnected system to connect the 21 remote communities north of Red Lake and Pickle Lake. The assessment identified a number of issues that make such an interconnection technically and economically infeasible:

- Neither Red Lake nor Pickle Lake are technically capable of supplying a majority of the communities, should supply from one of these sources not be available;
- Reliability is likely to be lower, as the interconnected system would be more exposed to weather systems and related outages;
- Higher cost, as more high voltage transmission line would be required relative to a radial system, and there would be a much larger need for voltage control devices; and
- Fewer cost economies from sharing centrally located transformer stations among communities.

To maintain reliability in the remote communities this Plan recommends that backup generation systems be available in the remote communities. One way of accomplishing this is to keep diesel fleet currently operating in the communities in an operable condition, so that it will be available to supply the communities during planned and unplanned transmission outages. It is expected that the current installed capacity of the fleet would be sufficient to supply local community needs in emergency situations until about 2030. This approach should ensure supply availability under most contingencies and has been used successfully by Five Nations Energy Inc. in supplying their communities for more than 10 years.

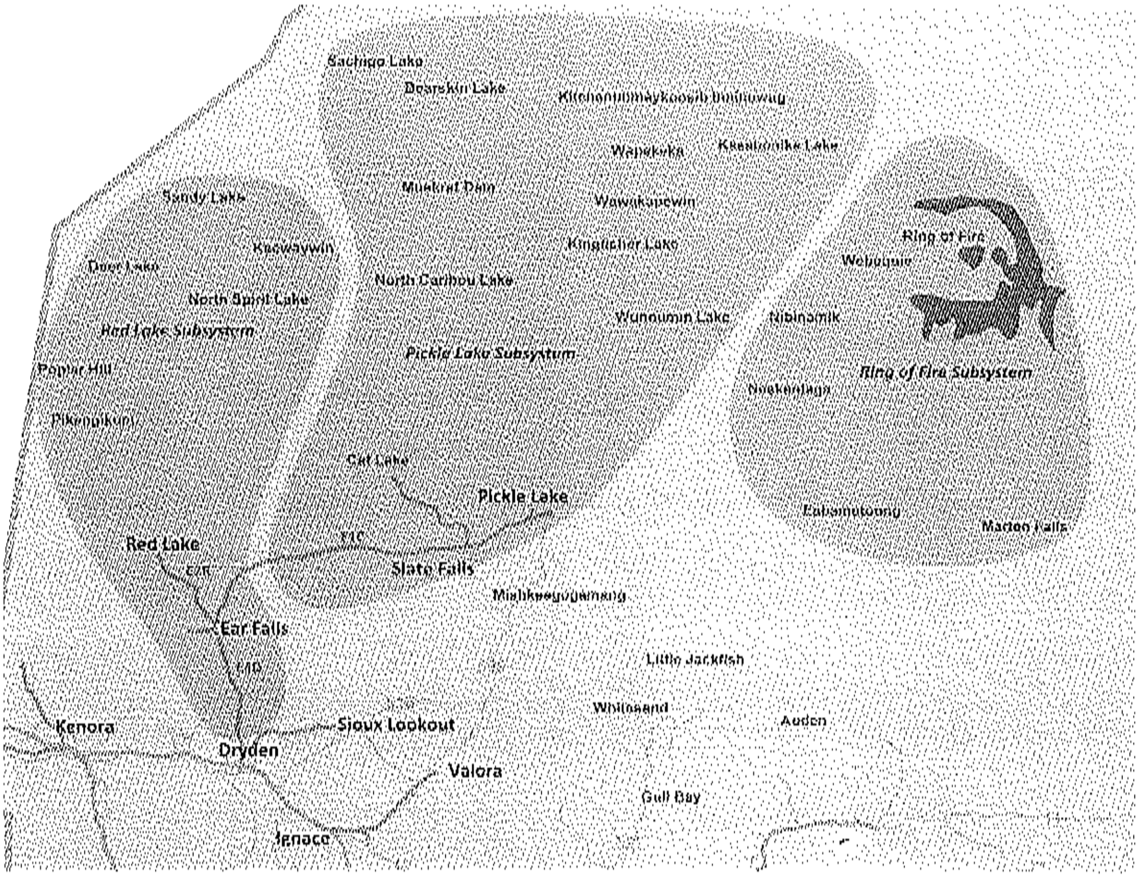
Studies undertaken by the OPA and the IESO have determined that the current transmission system north of Dryden, comprised of transmission lines E4D, E2R and E1C, does not have sufficient capacity to serve remote communities, projected mining load or the forecast growth in the Red Lake, Pickle Lake and Ring of Fire areas beyond 2014. Reinforcement of the system is therefore required to serve these identified needs.

The OPA has conducted a planning and feasibility study in parallel with the development of this report to ensure that there are options available to meet the load growth needs forecast for the connection of remote communities. Included in the OPA's estimates of the capital and operational costs to connect remote communities are estimates of a relevant share of the costs to reinforce Pickle Lake and Red Lake, and of the costs to provide power to the Ring of Fire. The upgrades and expansions of the north of Dryden area transmission system, which are included in this analysis are, the upgrade to E4D and E2R, the new line to Pickle Lake at 230 kV, and the shared line to communities and potentially the mines in the area of the Ring of Fire.

6.2 Geographic Configuration of the 21 Communities

The 21 communities are grouped into three subsystems based on geography and technical connection feasibility. The grouping configuration connects the six communities north of Red Lake, the ten communities north of Pickle Lake, and the five communities near the Ring of Fire as shown in Figure 17 below. These subsystems correspond to the subsystems described in OPA's Draft North of Dryden IRRP, released on August 16, 2013.

Figure 17: Red Lake, Pickle Lake and Ring of Fire Remote Subsystems



Source: OPA

The ten communities north of Pickle Lake are: Wunnumin Lake First Nation, Kingfisher Lake First Nation, Wawakapewin First Nation, Kasabonika Lake First Nation, Wapekeka First Nation, Kitchenuhmaykoosib Inninuwug First Nation, Bearskin Lake First Nation, Sachigo Lake First Nation, Muskrat Dam First Nation, and North Caribou Lake First Nation. These communities have an existing load of 7.5 MW which is forecast to grow to about 16 MW by 2034 and 36 MW by 2054.

The six communities north of the Town of Red Lake are: Pikangikum First Nation, Poplar Hill First Nation, North Spirit Lake First Nation, Deer Lake First Nation, Sandy Lake First Nation, and Keewaywin First Nation. These communities have an existing load of 7 MW, which is forecast to grow to 16 MW by 2034 and 35 MW by 2054.

The five communities located in the area of the Ring of Fire are: Eabametoong First Nation, Neskantaga First Nation, Webequie First Nation, Nibinamik First Nation, and Marten Falls First Nation. These communities have an existing load of 3 MW, which is forecast to grow to 7 MW by 2034 and 16 MW by 2054.

It is expected that each system from Red Lake, Pickle Lake, and / or the Nipigon / Marathon area can be developed independently, allowing the opportunity for multiple lines to be developed and built at the same time. This may reduce the overall time to completion. The OPA has developed a preferred connection option for the Pickle Lake subsystem (Figure 18), and the Red Lake subsystem (Figure 19), while there are two connection concepts for the Ring of Fire subsystem (Figure 20). The Ring of Fire subsystem configurations are differentiated by whether it is supplied by Pickle Lake, with or without the Ring of Fire mines, or by the transmission system near Nipigon / Marathon. If the Ring of Fire mines are supplied from Pickle Lake, then a new 230 kV supply at Pickle Lake would be required. It should be noted that current demand forecasts indicate the new line to Pickle Lake must be built to 230 kV standards. These line connection configurations were developed in consideration of the planning criteria outlined in the IESO ORTAC document.

6.3 Pickle Lake Subsystem

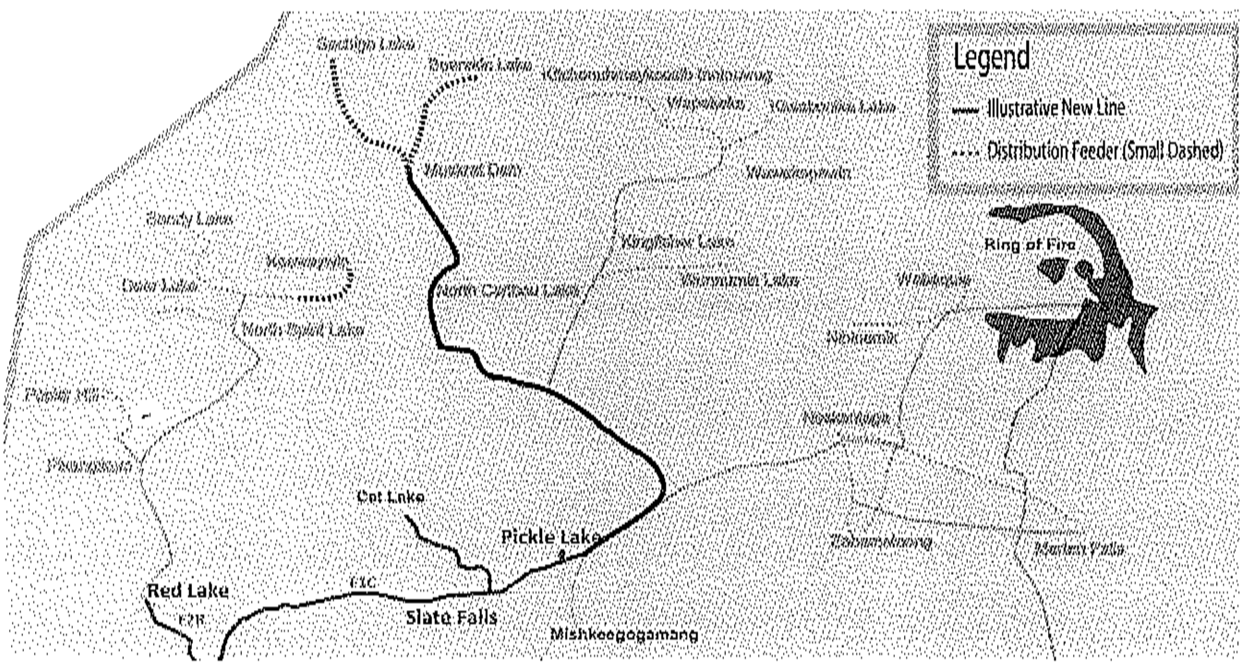
6.3.1 Overview

The supply option for the ten remote communities north of Pickle Lake is designed to connect them to the provincial transmission grid at Pickle Lake. For these communities to connect to Pickle Lake a new transmission line from the Dryden / Ignace area to Pickle Lake will be required as Pickle Lake currently does not have sufficient capacity to supply these remote communities.

Wataynikaneyap Power is a First Nations owned transmission line development company that is working with the ten communities north of Pickle Lake to develop an acceptable connection system. Wataynikaneyap Power has developed a transmission connection configuration through engagement with the communities north of Pickle Lake. The OPA has adopted this configuration in developing this Plan.

A radial system to supply the Pickle Lake subsystem may be developed in four sections. The project could begin construction as soon as the new line reinforcement to Pickle Lake is completed (proponents have indicated completion as early as 2017). It is expected that construction and commissioning of all of the sections could take about five years. Figure 18 shows how connection of this subsystem of 10 remote communities could be configured.

Figure 18: Pickle Lake Subsystem Conceptual Configuration



Source: OPA

6.3.2 <u>Pickle Lake to North Caribou Junction Line</u>

A new 150 km, 115 kV single-circuit line is expected to extend from Pickle Lake to a new station that is expected to be built until a split point that is about 100 km southeast of North Caribou Lake. This new line is planned to follow existing all-season and winter roads where possible. Following the split point, two lines will continue:

- North Caribou Junction to Muskrat Dam Line; and

- North Caribou Junction to Kingfisher Junction Line.

To maintain system voltage stability on these lines reactive compensation devices (series capacitors or an SVC) would need to be placed at this station where they would be able to manage voltage centrally for all of the other radial lines.

6.3.3 North Caribou Junction to Muskrat Dam Line

A new 115 kV single-circuit line from North Caribou Junction is planned to extend 190 km northwest from North Caribou Jct. to Muskrat Dam First Nation on a route passing North Caribou Lake First Nation. New transformer stations ("TSs") are planned at North Caribou Lake First Nation and at Muskrat Dam First Nation. From the new Muskrat Dam TS, two distribution feeders would run north. One feeder would connect Sachigo Lake First Nation and the other to connect Bearskin Lake First Nation. This feeder is capable of connecting some hydro generation sites along the Severn River system that First Nation communities in the area have identified as having high potential for development.

6.3.4 North Caribou Junction to Kingfisher Junction Line

A new 60 km, 115 kV single-circuit line is planned to extend from North Caribou Junction to Kingfisher Junction. At Kingfisher Junction, a new TS would be installed to serve Kingfisher Lake First Nation and Wunnumin Lake First Nation by distribution lines (44 kV or 27.6 kV).

6.3.5 Kingfisher Junction to Wawakepewin Line

A new 125 km, 115 kV single-circuit line is planned to extend from Kingfisher Junction to Wawakapewin First Nation. The Plan assumes a new TS could be located at Wawakapewin First Nation. Distribution feeders from Wawakapewin TS would supply Kasabonika Lake First Nation, Wapekeka First Nation and Kitchenuhmaykoosib Inninuwug First Nation.

6.4 Red Lake Subsystem

6.4.1 Overview

The supply option from Red Lake is designed to serve the six communities north of Red Lake with a new 115 kV single-circuit line. This new 115 kV line would extend the existing transmission system at Red Lake TS north toward Pikangikum First Nation, then to North Spirit Lake First Nation, and would terminate at a new TS south east of Sandy Lake First Nation. To supply these communities step-down transformer stations are planned close to Pikangikum First Nation, North Spirit Lake First Nation and a third at the end of the line south east of Sandy Lake First Nation. Each community is assumed to be connected to the closest TS with a distribution feeder (44 kV or 27.6 kV). Pikangikum First Nation, and Poplar Hill First Nation would be supplied by the first TS. Deer Lake First Nation and North Spirit Lake First Nation would be supplied by the second TS while Sandy Lake First Nation and Keewaywin First Nation would be supplied by the station south of Sandy Lake.

The project could begin construction once the supply reinforcements for Red Lake are completed (current expectation is for Red Lake to be reinforced by 2016 or 2017). It is expected that construction and commissioning of this project would take three to four years.

It is important to note that Pikangikum has expressed early interest in pursuing connection to the provincial grid at Red Lake independently. The analysis presented in this Plan assumes that all six communities in the Red Lake subsystem connect and share facilities as part of a single project.

6.4.2 Red Lake to Pikangikum Line

A new 90 km, 115 kV single-circuit line is planned to extend from Red Lake to Pikangikum is the first stage of development. It is assumed that a new TS could be located north of Pikangikum to serve Pikangikum First Nation and Poplar Hill First Nation at a distribution voltage level (44 kV or 27.6 kV).

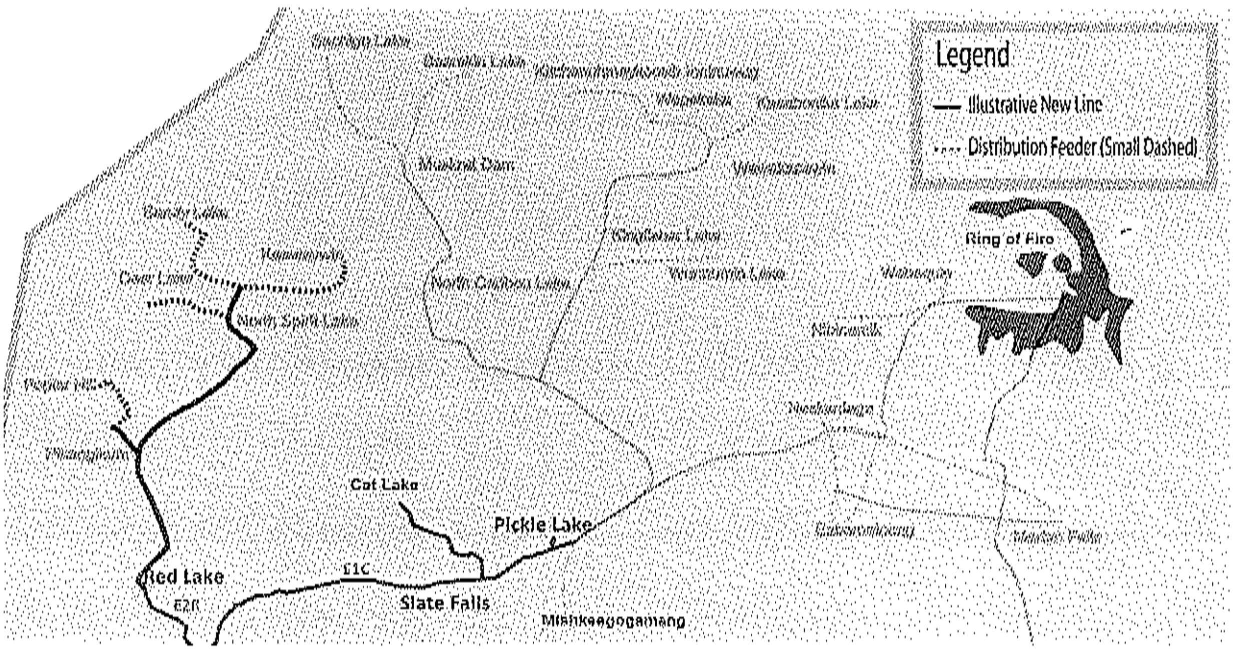
6.4.3 Pikangikum to North Spirit Lake

A new 125 km, 115 kV single-circuit line is planned to extend from Pikangikum to North Spirit Lake. The Plan assumes that a new TS could be located northwest of North Spirit Lake to serve North Spirit Lake First Nation and Deer Lake First Nation at a distribution voltage level.

6.4.4 North Spirit Lake to Sandy Lake Junction

A new 45 km, 115 kV single-circuit line is planned to extend from North Spirit Lake to an area southeast of Sandy Lake called Sandy Lake Junction. A new TS is assumed to be built at Sandy Lake Junction to supply Sandy Lake First Nation and Keewaywin First Nation at a distribution voltage level.

Figure 19: Red Lake Subsystem Conceptual Configuration



Source: OPA

6.5 Ring of Fire Subsystem

6.5.1 Overview

Four potential configurations have been identified for the subsystem of five communities in the area of the Ring of Fire based on whether or not a new line from Pickle Lake will be built to supply potential mining developments at the Ring of Fire. The first case includes connection of the five communities at Pickle Lake via a new 115 kV line. This case assumes that the Ring of Fire does not connect to the transmission system. The remaining three cases assume the Ring of Fire does connect to the transmission system and that transmission lines will be shared by the five communities and the Ring of Fire proponents. The second case includes a new 115 kV line from Pickle Lake, the third case includes a new 230 kV line from Pickle Lake, and the fourth case includes a new 230 kV line from the Nipigon / Marathon area.

In this study, it is assumed that proponents pay for transmission and distribution facilities in proportion to the peak electrical demand they place on those facilities. Given this, sharing a 115 kV line with the Ring of Fire proponents would result in lower costs for the remote communities than a 115 kV line dedicated only to the communities. It is important to recognize, however, that this potential for cost sharing is dependent on degree of load growth at the Ring of Fire, the desire for mining customers to connect to the transmission system, and the Ring of Fire mines paying their share of project capital costs as prescribed by the Transmission and Distribution Codes issued by the OEB. For scenarios where there is higher load at Ring of Fire (scenarios three and four) a lower cost would result for the remote communities.

The OPA has identified the potential for 22 – 71 MW of industrial load at the Ring of Fire to develop after 2017. Analysis shows that to serve this load from Pickle Lake, 230 kV supply at Pickle Lake would be required and that a single 115 kV line from Pickle Lake to the Ring of Fire could supply the needs of the five remote communities and up to about 40 MW of load at the Ring of Fire. Supply beyond these levels will require that the line to Ring of Fire and the communities be built to 230 kV standards or a second 115 kV line be built from Pickle Lake to the Ring of Fire.

As discussed above, 230 kV supply at Pickle Lake is required to supply the Ring of Fire from Pickle Lake. This line will be sufficient to serve the entire Pickle Lake area load including the 10 remote communities north of Pickle Lake, the five communities in the area of the Ring of Fire and the maximum expected electrical demand at the Ring of Fire within the planning period. Red Lake area growth including connection of the 6 remote communities north of Red Lake can be served by upgrading the existing lines between Dryden and Red Lake (E4D and E2R) and / or by the new line to Pickle Lake[28].

The OPA's load forecast for the remote communities in the Ring of Fire area is about 7 MW by 2034. The forecast for Ring of Fire anticipates about 22 MW by 2020, with the potential to grow to about 71 MW within the planning period. The current mine development timelines suggest that a transmission line to the Ring of Fire could be required as early as 2017, which would require co-development of this facility with the new 230 kV line planned to Pickle Lake. For the connection scenarios presented below, there are assumed cost sharing ratios, depending on the expected electricity demand at the Ring of Fire mines. The cost sharing ratios are applied to all capital and O&M costs that are shared by the communities and the mines.

6.5.2 115 kV Supply to Remote Communities from Pickle Lake

This transmission supply option for the five communities in the Ring of Fire area assumes that the Ring of Fire is not connecting to the transmission system. This option consists of a new 210 km; single-circuit 115 kV transmission line would be built from Pickle Lake to the Webequie area.

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[28] The new line to Pickle Lake can create some capacity in the Red Lake area (when E1C, the line between Ear Falls and Pickle Lake becomes supplied by the new line to Pickle Lake). The availability of capacity in the Red Lake area following the installation of the new line to Pickle Lake will depend on timing of applications from customers in the Red Lake area.

6.5.3 115 kV Supply to Remote Communities and Ring of Fire from Pickle Lake

To supply industrial customers at the Ring of Fire as well as Eabametoong First Nation, Neskantaga First Nation, Nibinamik First Nation, Marten Falls First Nation, and Webequie First Nation a new 290 km, single-circuit 115 kV transmission line would be built from Pickle Lake to the McFaulds Lake area. Routing would be optimized to minimize the connection costs for these First Nation communities, while also following a potential transportation corridor currently being planned from the McFaulds Lake area to Pickle Lake via Webequie. There are both cost and line performance synergies created by connecting these communities to a line supplying the Ring of Fire.

A cost sharing arrangement based on proportional use (peak demand over the next 20 years) would suggest that approximately 25 percent of the cost of the line (based on 7.5 MW of load) could be allocated for remote community connections, while the mining customers at the Ring of Fire are assumed to contribute approximately 75 percent. The remote connection plan would also be responsible for the cost of the connection facilities (transformer stations, distribution lines, and distribution stations), which are required to connect the five communities to the transmission line.

6.5.4 230 kV Supply to Remote Communities and Ring of Fire from Pickle Lake

To supply industrial customers at the Ring of Fire as well as Eabametoong First Nation, Neskantaga First Nation, Nibinamik First Nation, Marten Falls First Nation, and Webequie First Nation a new 350 km, single-circuit 230 kV transmission line would be built from Pickle Lake to the McFaulds Lake area. Routing would be optimized to minimize the connection costs for these communities, while also following a potential transportation corridor currently being planned from the McFaulds Lake area to Pickle Lake via Webequie. There are both cost and line performance synergies created by connecting these communities to a line supplying the Ring of Fire. This supply option assumes that the demand at the Ring of Fire would reach 71 MW by 2034.

A cost sharing arrangement based on proportional use (in the long term) would suggest that approximately 10 percent of the cost of the line (based on 7.5 MW of load) could be allocated for the remote community connections, while the mining customers at the Ring of Fire are assumed to contribute approximately 90 percent. The remote connection plan would also be responsible for the cost of the connection facilities (transformer stations, distribution lines, and distribution stations) where required to connect the five communities to the transmission line.

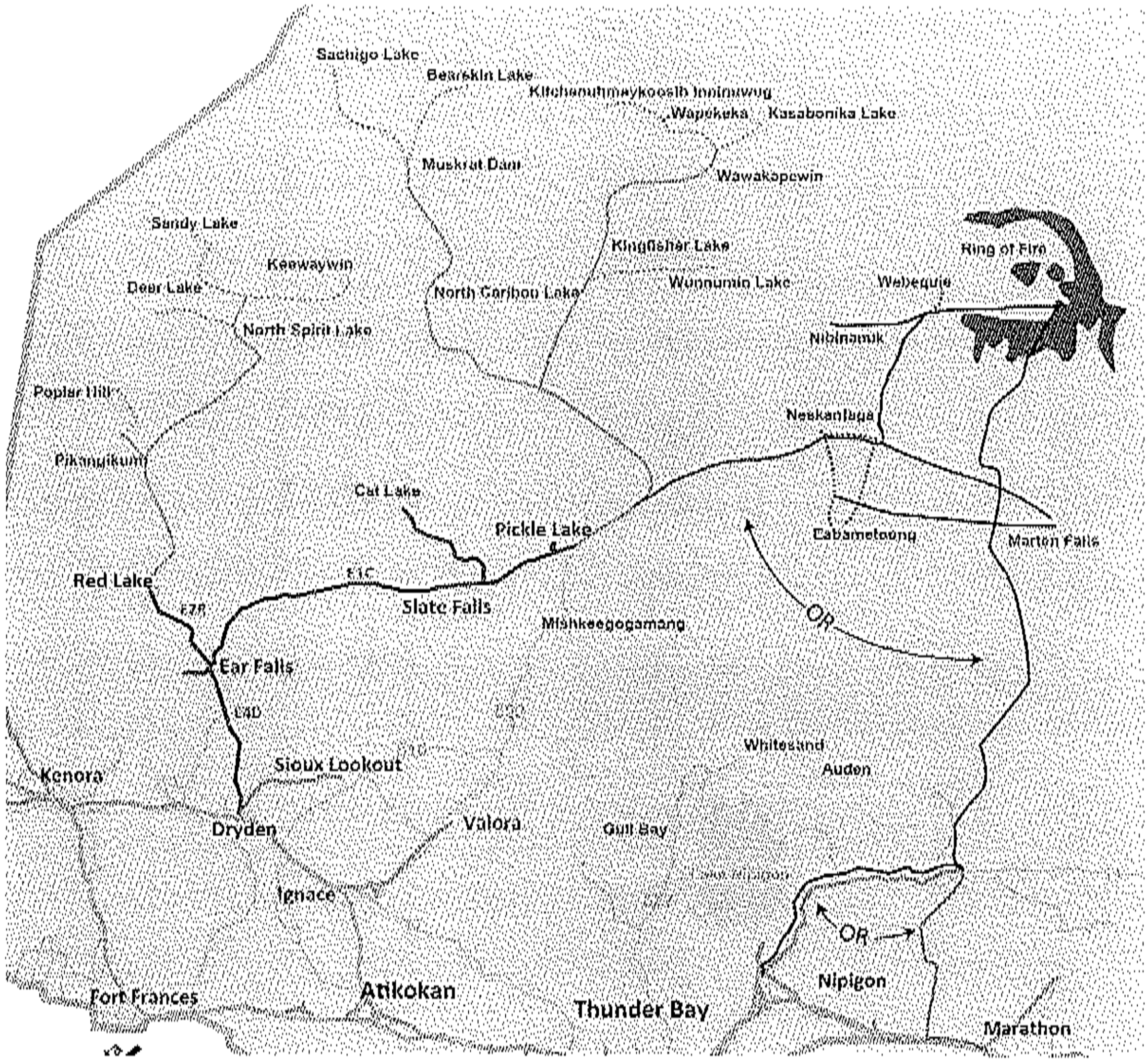
6.5.5 230 kV Supply to Remote Communities and Ring of Fire from the Nipigon / Marathon Area

To supply industrial customers at the Ring of Fire as well as Eabametoong First Nation, Neskantaga First Nation, Nibinamik First Nation, Marten Falls First Nation, and Webequie First Nation a new 550 km, single-circuit 230 kV transmission line would be built from the Nipigon / Marathon area to the McFaulds Lake area. Routing would be optimized to minimize the connection costs for these First Nations, while also following a potential transportation corridor currently being planned from the McFaulds Lake area to Pickle Lake via Webequie. There are both cost and line performance synergies created by connecting these communities to a line supplying the Ring of Fire. This supply option assumes that the demand at the Ring of Fire would reach 71 MW by 2034.

A cost sharing arrangement based on proportional use (in the long term) would suggest that approximately 10 percent of the cost of the line (based on 7 MW of load) could be allocated for the remote community connections, while the mining customers at the Ring of Fire are assumed to contribute approximately 90 percent. The remote connection plan would also be responsible for the cost of the connection facilities (transformer stations, distribution lines, and distribution stations) where required to connect the five communities to the transmission line.

An illustrative diagram of the supply options for the Ring of Fire subsystem can be found in Figure 20 below. The purple line that runs from Pickle Lake could be built at either 115 kV or 230 kV. Alternatively, the blue line would connect the communities and the mines via 230 kV transmission line from the Nipigon / Marathon area.

Figure 20: Supply Options for Ring of Fire Subsystem



Source: OPA

Table 22 below summarizes the line distances and costs for each of the line projects under all potential connection configurations of the Ring of Fire subsystem of communities. As noted elsewhere, each of these scenarios is dependent on upgrades to the existing system in the Red Lake and Pickle Lake areas.

Table 22: Summary of Remote Community Connection Lines

Subsystem	Transmission Line (km)	Distribution Line (km)	Transformer Stations	Distribution Stations
Pickle Lake Subsystem	530	400	4	10
Red Lake Subsystem	260	200	3	6
Ring of Fire Subsystem, Communities Only	210	325	2	5
Ring of Fire Subsystem from Pickle Lake 115 kV	300	350	3	5
Ring of Fire Subsystem from Pickle Lake 230 kV	350	350	3	5
Ring of Fire Subsystem from Nipigon/Marathon 230 kV	700	275	4	5

Source: OPA

7.0 COMMUNITY ENGAGEMENT

It is important to note that the OPA's work on remote connections is a result of a close working relationship with the Committee. Additionally, since the release of a draft version of the Remote Community Connection Plan in summer 2012, the OPA has engaged with many of the remote communities to provide information on the analysis and conclusions in the Plan. The OPA's engagement has varied by community and has included: meetings with Chiefs and Councils, meetings with community members, as well as the providing of information through local radio and television broadcasts. Engagement with community members has often also included the presence of a translator from the community. To date the OPA has engaged with 17 of the communities included in the Plan and overall there has been strong support expressed given the benefits which can be realized. Key concerns raised during engagement included the potential for local renewable energy projects, the impact of transmission lines on the environment, and local job opportunities, among other things. The communities that OPA has engaged with to date are:

1. Bearskin Lake
2. Fort Severn
3. Kasabonika Lake
4. Keewaywin
5. Kingfisher Lake
6. Kitchenuhmaykoosib Inninuwug
7. Muskrat Dam
8. North Caribou Lake
9. North Spirit Lake
10. Poplar Hill
11. Sachigo Lake
12. Sandy Lake
13. Wapekeka
14. Wawakapewin
15. Weenusk (Peawanuck)
16. Whitesand
17. Wunnumin Lake

The communities that still need to be engaged are:

1. Deer Lake
2. Eabametoong
3. Kiaashke Zaaging Anishinaabek (Gull Bay)

4. Marten Falls
5. Neskantaga
6. Nibinamik
7. Pikangikum
8. Webequie

This Plan will be finalized only following engagement with all 25 communities.

8.0 DEVELOPMENT WORK REQUIRED AND TIMELINES

The following tasks will be necessary to develop the lines in this Plan:

- Negotiation of a cost- and risk-sharing agreement between the various benefitting parties;
- Identification of a transmitter for project development;
- Detailed technical system studies, such as a System Impact Assessment by the IESO, and a Customer Impact Assessment by the Transmitter;
- Route and site identification and assessment;
- Preliminary engineering;
- Preparation and submission of EA Terms of Reference;
- EA studies and field work, EA approval; and
- Preparation and submission of Leave to Construct application.

Delays in commencing and / or completing any of the tasks will lead to delays in the timing of some or all of the communities being connected. An additional factor not discussed in detail in this Plan is the process and framework for arranging financing for these projects. Substantial near term investment will be required in order to realize the long-term benefits of reducing diesel use for electricity generation. To ensure successful project implementation, these investments should be made by the parties that stand to benefit, and should reflect the expected changes in those benefits over time. As discussed in Chapter 2, in order to implement a plan for transmission connection, the federal government, the province (representing both the rate base and tax base), the remote communities included in this Plan for connection and any participating industrial customers will need to come to agreement on the extent of costs to be shared and the allocation of those costs among them.

The Far North Act, being implemented by Ontario Ministry of Natural Resources, requires that all communities conduct land use planning prior to commencing the development of new transmission facilities; thus, the development timelines identified in this Plan to connect remote communities may be affected by the progress communities make in completing their land use plans.

Appendix A

Probabilistic Uncertainty Analysis to Supplement the Remote Community Connection Plan's Financial Model

Introduction and Purpose

The Remote Community Connection Plan's financial model is used to estimate the financial benefit of connecting remote communities in Ontario's far north to the IESO controlled grid. The model is set up such that it uses fixed values for several key variables (among many others), which are critical to estimating the economic benefit of transmission connection. Its output or results are an estimate of the net benefit that is expected from the project. These key variables are growth in electrical demand, cost of fuel delivered to the communities, the capital cost of the transmission facilities, and the capital cost for new renewable technology. The fixed values were chosen through researching reliable industry resources, data from H1RCI and AANDC, and the application of professional judgment to relate the industry sourced values to the model. It is however recognized that these variables are not discrete and can be represented by probability distributions that account for the inherent uncertainty associated with each of them.

The following analysis has been conducted to define and quantify the probability distributions for these variables and to determine the effect that the related uncertainty has on the outcomes estimated by the model. To quantify the uncertainty associated with each variable, the following process was used:

- Determine which variables from the connection model have the highest degree of uncertainty;
- Define reasonable distributions for these variables;
- Define reasonable ranges for these variables; and
- Understand how the outputs are related to the input variables (perhaps not linear), and use this understanding to determine whether the variables, distributions and ranges are still reasonable

The purpose of this analysis is to quantify the degree of uncertainty, which exists for each and the combination of the key variables in the study and the effect this has on the certainty of the business case for connection of the Remote Communities. The probabilistic range of results provides the reader with an estimate of the certainty that the project will have a positive NPV (i.e. the transmission connection case is lower cost than the continued diesel case), over a significant range of the input variables.

Methodology

The tool used for this analysis is @Risk, which is an excel-based uncertainty tool. The financial model used for the business case analysis in this report is based in excel, and can be used directly with the @Risk tool. @Risk uses Monte Carlo simulation, which generates a value for a variable based on the probability of an outcome given a defined distribution. This tool was chosen for this analysis because of the ease of integration with the existing financial model, and the well-established use of Monte Carlo simulation for risk analysis.

The first step in this uncertainty analysis was to determine variables to be included in the probabilistic analysis. Variables that were found to most strongly drive the outcomes of the business model as well as having potential uncertainty include community electricity demand growth, diesel fuel price, transmission capital costs, and renewable technology costs. These variables were assigned probability distributions based on their likely range of uncertainty. The availability of independent, industry-based forecast information helped determine the characteristics of the probability distributions. The remaining input variables individually have only small impacts on the net benefit results and thus were not considered meaningful to manipulate.

These variables were then assigned distributions based on how the upside and downside risks of the variables are weighted. Due to the relative conservativeness of the original input variables, normal distributions were chosen because it is believed that there is an inherent balance between the risks on both sides of the average of these variables.

In this analysis, a variety of forecasts for diesel price growth were analyzed and through professional judgment the more conservative EIA Annual Energy Outlook 2013 forecast was chosen. With regard to transmission costs the OPA commissioned an experienced third party consultant to estimate unit costs for transmission projects undertaken in the Far North. The values used for community demand growth were developed by the Northern

Ontario First Nation Transmission Planning Committee's members that have the experience and relevant information to forecast population growth and economic development potential that are the main drivers of electricity demand in their communities. Additionally, historical trends for electrical demand growth in H1RCI communities were reviewed to provide another check on the demand growth assumption. The historical H1RCI electricity demand growth supported this assumption. The OPA believes that the probability distributions for these variables, summarized in Table 23 below, ensure a broad but realistic range for each.

Table 23: Summary of Statistics for Input Variable Distributions

	5%	95%	Mean	Standard Deviation
Real Diesel Price Growth Rate Adjustment (%)[29]	-33%	33%	0%	20%
Community Demand Growth (%)	2.0%	6.0%	4.0%	1.2%
Transmission Cost Adjustment (%)	-25%	25%	0.0%	15%
Renewable Resources Cost Adjustment (%)	-20%	20%	0.0%	12%

Inputs and Justification

The key variables that influence the cost benefit of the Remote Community Connection Plan are:

- Real diesel price growth rate adjustment: while forecasts are available, future expected values of commodities are constantly changing.
- Community demand growth: community demand is expected to increase due to population and economic activity growth. This variable influences the amount of

[29] The following chart maps the observed impact of the diesel price adjustment factor to the corresponding average diesel price growth rate and the diesel price forecast for 2054

	Mean	5%	95%
Diesel Price Adjustment (%)	0.0	-33	33
Average diesel price growth rate 2014-2054 (%)	1.32	0.2	1.9
Diesel price 2054 ($2014/L)	1.59	1.07	2.10

diesel fuel required and the energy-based supply expansion costs in the continued diesel operation case and the electricity cost in the transmission connection case.

- Transmission capital cost: the cost of building transmission infrastructure is uncertain given the large number of interrelated factors. The scale and scope of this development in the far north suggests a broad range of costs should be studied.
- Capital cost for renewable technology: the cost of building on-site renewable solutions is uncertain given the unique environment and the challenges with transportation of devices, among other things.

Each of these variables was assigned distributions as follows.

Real diesel price growth rate adjustment:

The distribution chosen for this variable was the normal distribution, applied to the year-by-year forecast growth. The 2013 rack rate in Thunder Bay was assumed to be the base year value. Each year, a deviation from the expected forecast growth is given based on this distribution. On average, the year-to-year price growth rate is the same as is used in the business case. The adjustment ranged by about 33 percent above and below the year-to-year growth in the forecast (i.e. if growth was forecast at one percent from one year to the next, variation resulted in a potential range of 0.67 percent to 1.33 percent for that year).

Since this allows for the growth in diesel price to have an overall negative real growth, the OPA believes that this factor will show the overall robustness of the analysis. Table 23 above summarizes the statistics generated for this variable.

Community demand growth:

A normal distribution was used for this variable; with a mean value four percent per year. It was observed that high demand growth combined with high diesel price growth has a tendency (due to compounding) to slightly bias the expected NPV distribution towards the upside. It should be noted, however, that the median case corresponds to the base case. In simulation, this variable ranged from about one percent yearly growth to about seven percent, which stressed the model and led to large range of NPV outcomes. A summary of the statistics for the community demand growth distribution is provided in Table 23 above.

<u>Transmission capital cost:</u>

This variable was assumed to have a normal distribution, since conservative estimates of transmission development, construction and operation have already been used in the base case. Thus it is considered equally likely that the cost will be higher or lower than estimated. Since project costs can vary widely, the maximum deviation from the assumed cost was 25 percent above and 25 percent below average. A summary of the statistics is provided in Table 23 above. This range allowed for the maximum and minimum band of outcomes to correspond with the uncertainty of the cost estimates used in the report, which is plus or minus 50 percent.

<u>Renewable Resources capital cost:</u>

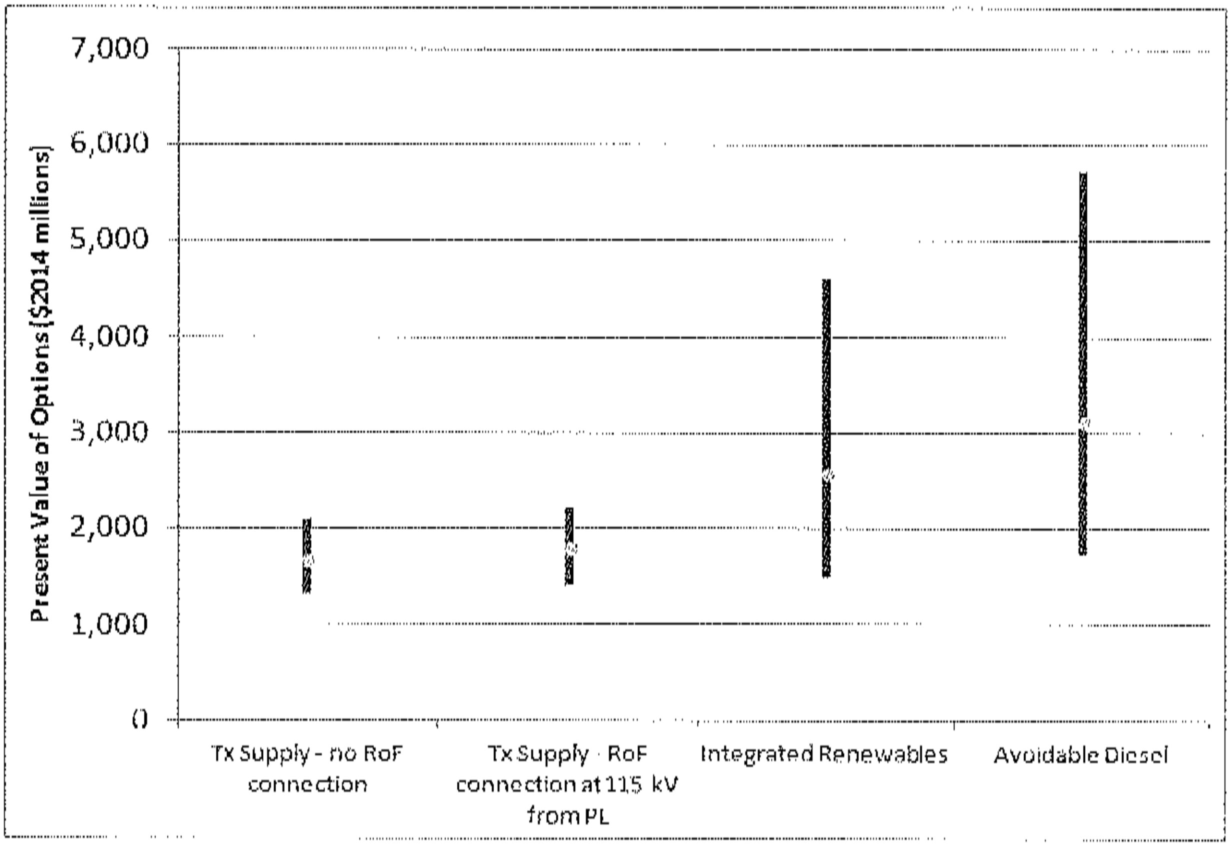
This variable was assumed to have a normal distribution, since cost estimates currently account for additional costs due to more sophisticated technology needs for the climate and higher transport cost of materials. Thus it is considered equally likely that the cost will be higher or lower than estimated. Since project costs can vary widely, the maximum deviation from the assumed cost was 20 percent above and 20 percent below average. A summary of the statistics is provided in Table 23 above.

Once the distributions were established, the next step was to set up the simulation set, the results of which are summarized below.

Results and Observations

This analysis was applied to the two transmission connection scenarios for the Ring of Fire subsystem of communities identified in the Committee's connection plan. The first scenario assumes that the communities in the Ring of Fire subsystem will connect to Pickle Lake via a 115 kV single-circuit line from Pickle Lake, and that the Ring of Fire mines will not connect. The second scenario assumes the Ring of Fire mines (22 MW) and the communities in the Ring of Fire subsystem connect to Pickle Lake via a 115 kV single circuit line. The scenarios have different assumptions about capital contributions from other customers sharing facilities with the remote communities. This is the main contributor to the difference in the cost for transmission connection in each scenario. The uncertainty simulation was also tested for the continued supply by diesel alternative, as well as the alternative to augment the current diesel supply with renewable generation. Figure 21 below illustrates the 90 percent confidence intervals for the present value of transmission and diesel costs for both scenarios.

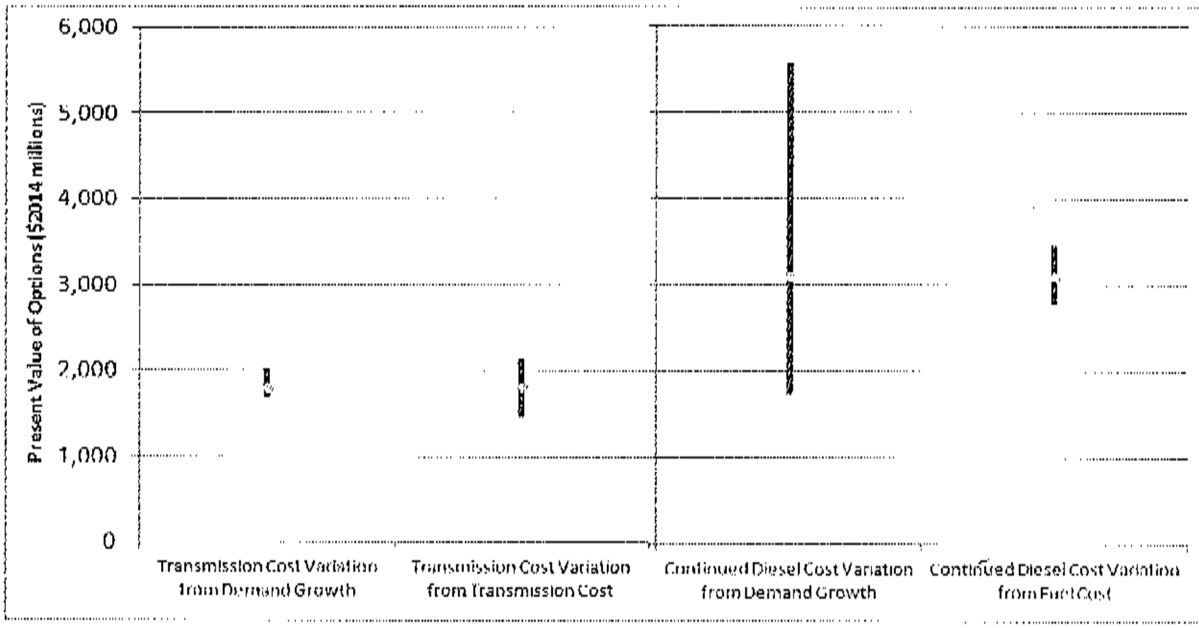
Figure 21: 90 Percent Confidence Interval of Alternatives



Source: OPA

Analysis was also conducted by varying only one variable in each simulation to show the relative amount of variation for each of the key variables. For the cases shown in Figure 22 the entire variation in the NPV is attributable to the variation of the one tested variable.

Figure 22: Variations in Present Value of Transmission Connection Base Case (Communities Only) and Continued Diesel by Variable, 90 Percent Confidence Intervals



Source: OPA

It is noted that for the supply by transmission scenario, the variation of electricity demand has a small impact on the present cost for transmission supply and the variation of transmission capital cost results in a wider band of uncertainty in the present cost. This degree of variation or uncertainty in the estimated present cost for transmission supply contrasts very strongly with the observations for the diesel case variables as shown in Figure 22.

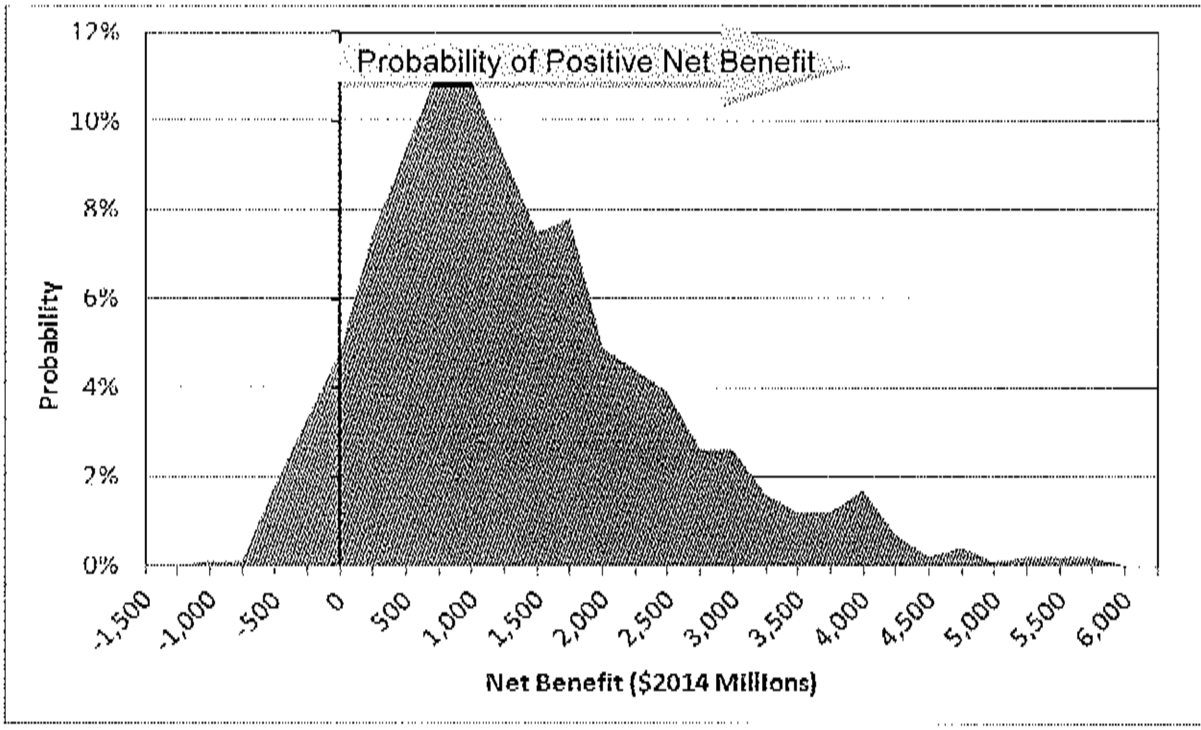
From Figure 22 above, it is clear that electricity demand growth is the overriding driver of variation in the supply by diesel case. In this case, demand growth plays a large role because it affects the total cost by increasing the volume of diesel consumed and leads to the expansion of diesel generation capacity. Whereas in the transmission connection cases (which are characterized by mostly fixed capital and operating costs, that are known when the project is built) do not vary significantly over the life of the project. The total cost of energy supplied by transmission is not greatly affected by changes in demand because the cost of power consumed is a comparatively small cost.

The load growth variable gives a slight positive skew to the confidence interval for the diesel case. This occurs because compounding values that are above the mean produces values that are farther from the mean than compounding values below the mean. Since the other variables do not compound in the same way, their impact on the overall cost is very close to equal above and below the average.

Despite the wide variability of estimates for transmission costs, the 90 percent confidence interval for the transmission case has a smaller range compared to the diesel case costs. This is largely due to the insensitivity of the transmission case to the compounding impact of demand growth.

The transmission case is shown to cost more than the diesel case in a minority of scenarios generally where diesel price growth and demand growth are both low) or where demand growth is more than one standard deviation below its average. This is borne out by the low probability of negative NPV results in the following charts and the relatively smaller size of negative outcomes versus positive outcomes.

Figure 23: Net Present Value Distribution of Base Case (Communities Only)



Note: this chart does not include the renewable resources case as the net benefit results are concentrated in the small range of $0M - $500M (98 percent of results) due to the alternative being highly correlated with the avoidable diesel case. Displaying all alternatives would skew the scale of the graphic.

Source: OPA

Both transmission scenarios, with or without Ring of Fire connection, have more than a 90 percent probability of positive NPV. This indicates that over the 40 year period (2014 to 2054), transmission connection is expected to result in a lower cost than continued diesel operation in at least 90 percent of the simulated scenarios. Negative NPV outcomes are possible when demand growth is consistently one or more standard deviations below the average for the planning period and the other variables are also at or below their expected values.

Although normal distributions were used for all of the input variables, the output (NPV) appears to be positively skewed indicating that there is more upside benefit to transmission connection than downside risk – there is a reasonable probability of a high or very high positive NPV and a low probability of negative NPV.

Summary

Given the high likelihood of a positive NPV and the comparatively low range of uncertainty around the cost of the transmission case, this project exhibits a relatively low risk profile in comparison to the status quo option of continued diesel operation. While negative NPV outcomes are possible (less than 10 percent of input combinations modeled), a significantly more pessimistic view of the future than is reasonably expected would be required for this project to be considered too uncertain and / or uneconomic to undertake at this time.

The analysis undertaken here only considers the direct costs of transmission and the avoidable costs of diesel generation. There are costs and risks that have not been accounted for in this analysis, which include but are not limited to serious environmental events (fuel spills and site contamination), GHG emissions and lost social and economic development opportunities. The majority of unaccounted for risks and impacts would increase the expected cost and uncertainty of the status quo continued diesel option and would thereby increase the positive economic value of this project, if they were quantified and included in this analysis. Mitigating these risks and enabling future opportunities are key features of the transmission connection option. Attempting to mitigate these risks in the diesel option would likely be prohibitively expensive.

Appendix B

Discussion of Expected Reliability Post-Connection

Purpose and Introduction

The purpose of this appendix is to provide information on how the reliability performance to customers in the remote communities planned for connection to the IESO-controlled grid is expected to change once the communities are connected.

Reliability of electricity supply refers to the ability of the power system to provide customers with a continuous supply of electricity at proper voltage and frequency. The electricity industry typically measures reliability by identifying how many times in a year the supply of electricity to a customer is interrupted (interruption frequency) and how long a customer is interrupted (interruption duration) in a year. Common statistics that are used for measuring reliability are the System Average Interruption Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). SAIDI measures the expected time of outage per year, per customer, while SAIFI measures the number of outages per customer, per year.

Current Reliability

Historical reliability data for H1RCI communities can be found in Table 24.

Table 24: H1RCI Reliability Measures 2009 – 2011

Performance Measure	2009 Actual	2010 Actual	2011 Actual
SAIFI (# of interruptions per customer)	11.5	8.1	7.8
SIADI (hours of interruption per customer)	9.4	10.9	8.3

Source: H1RCI 2013 Rate Application dated September 17, 2012

Historical reliability for IPA communities is unavailable. From discussions with community members, the OPA understands that some communities have outages every one to two weeks, with outages lasting as long as a few days. This level of reliability significantly reduces the quality of life for people in these communities, by impacting the use of fridges and freezers, laundry machines, stoves, heating and lighting. Outages most notably have an effect on food storage as many communities continue to live off the land.

Expected Reliability

Following connection of the communities, reliability will no longer be solely dependent on the availability of the diesel generation and the performance of the local distribution system. Reliability will be dependent on the transmission system performance, the distribution system performance and the availability of the backup generation sources. Transmission outages can be the result of either planned maintenance, or an unplanned fault (contact with lightening, trees, animals, etc.) on the line. Planned maintenance outages may be longer in duration, but they are expected and alternative supply, such as backup generation, can be arranged. Unplanned outages are unpredictable and are generally the result of a few key factors, including:

- Weather and climate;
- Right of way clearing practices;
- Distance of the line (exposure);
- Direction of the line; and
- Design of the line.

Weather and climate can impact the reliability of a transmission line as severe weather (high winds, lightning, heavy snow, ice storms, etc.) tends to increase the probability of a fault on a line. Generally, the impact of weather and climate are similar for a geographic region.

A frequent cause of outages is tree contacts with the wires. This can be minimized by frequently surveys of the line and tree trimming to acceptable distances from the line. If this is done prudently and consistently, outages can be avoided.

The length of a line will dictate its exposure to the elements. More distance results in more likelihood of potential interruptions. Lines can be sectionalized to reduce exposure to some or all customers using the line. Sectionalization is when a device (like a breaker or disconnect switch) is used to isolate the affected section of the line from the rest of the system, so that service can be restored to some customers. The lines discussed in this report for connection of remote communities are radial lines. Sectionalization can reduce outage frequency for customers that are further south, by using switching devices to limit the exposure for these customers. The customers that are furthest north will have the highest exposure, as they rely on the entire length of the line for delivery of power.

The direction of the line may also have an impact on the frequency of unplanned outages. In some regions, severe weather tends to travel in particular directions. If the path of severe weather follows the length of the line, there is more potential for the weather to have an impact on the line. Similarly, if the weather travels perpendicular to the line, the weather will only have contact with the line for a short period of time, reducing the potential for impact on electricity service.

The probability of outage for a particular line can also be impacted by the design of the transmission line. Design features can be use to limit the potential for circuit-to-circuit contact, or the potential for lightening strike, among other things.

With these factors in mind, OPA estimated the expected outage frequency and duration for communities after connection to the provincial transmission grid in Table 25. This outage data assumes that the new lines will have similar performance to existing lines in northwest Ontario. It was also assumed that, where transformer stations are located, there will also be line sectionalization limiting exposure for some communities.

This expected outage data does not include any potential additional design features that may be used to improve electricity supply reliability. This data also does not consider how the backup diesel generators may mitigate outages for communities. OPA assumes that the existing diesel generators are maintained in operable condition, so that they could be used to maintain electricity service for critical customers during sustained outages.

Summary

The expected outage duration for transmission supply alone is estimated to be an improvement for IPA communities, but not generally for the average H1RCI community.

However, with the use of backup generation to mitigate the transmission system outages, it may be possible to improve outage frequency and duration for all communities.

Table 25: Expected Outage Time Post-Connection by Community

	Planned Outages			Forced Outages				Total Outages	
Community	Planned Outages/year	Planned Outage time (hr/yr)	Percent of time	Momentary Forced Outages/year	Sustained Forced Outages/year	Sustained Forced Outage time (hr/yr)	Percent of time	Total Outage Time (hr/yr)	Total percent of time
Deer Lake	6	81	0.9%	6	17	38	0.4%	119.15	1.36%
North Spirit Lake	5	69	0.8%	5	13	29	0.3%	97.60	1.11%
Poplar Hill	4	54	0.6%	4	11	26	0.3%	79.81	0.91%
Pikangikum	4	49	0.6%	4	10	22	0.3%	70.86	0.81%
Kee way win and Koocheching	7	82	0.9%	6	16	36	0.4%	118.26	1.35%
Sandy Lake	7	85	1.0%	7	17	38	0.4%	122.24	1.40%
Kingfisher Lake	6	79	0.9%	6	18	42	0.5%	120.81	1.38%
Wawakepewin	8	97	1.1%	6	25	56	0.6%	153.06	1.75%
Kasabonika Lake	8	106	1.2%	7	28	63	0.7%	169.30	1.93%
Wunnumin Lake	7	86	1.0%	6	21	48	0.5%	133.84	1.53%
Wapekeka	9	112	1.3%	7	29	67	0.8%	178.57	2.04%
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	9	115	1.3%	7	30	69	0.8%	183.22	2.09%
Bearskin Lake	8	97	1.1%	7	23	52	0.6%	148.70	1.70%
Muskrat Dam	6	81	0.9%	6	20	45	0.5%	126.21	1.44%
Weagamow (North Caribou Lake)	6	70	0.8%	5	16	37	0.4%	106.66	1.22%
Sachigo Lake	8	97	1.1%	7	23	52	0.6%	148.48	1.70%
Eabametoong (Fort Hope)	7	86	1.0%	6	19	44	0.5%	130.32	1.49%
Landsdowne House (Neskantaga)	6	77	0.9%	5	18	42	0.5%	118.92	1.36%
Webequie	7	92	1.1%	7	21	47	0.5%	139.12	1.59%
Nibinamik (Summer Beaver)	8	101	1.2%	7	24	56	0.6%	156.52	1.79%
Marten Falls	8	99	1.1%	7	25	57	0.7%	156.37	1.79%

Source: OPA, IESO