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NORTH SLAVE RESILIENCY STUDY

FINAL REPORT

Prepared for the Government of the Northwest Territories

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Manitoba Hydro International
211 Commerce Drive
Winnipeg, Manitoba
R3P 1A3 Canada
mhi.ca

Manitoba
HYDRO INTERNATIONAL

EXECUTIVE SUMMARY

Thermal generation cost changes due to water availability fluctuations are one of the basic cost realities of any hydro system, and can be particularly severe on an isolated hydro system such as the North Slave.

Recent drought and low water conditions at the Snare and Bluefish hydroelectric facilities dramatically increased diesel generation requirements and costs on the North Slave hydroelectric system. There was no rate method in place to deal adequately with the material diesel generation costs driven by this fluctuation in water availability.

The GNWT subsequently retained Manitoba Hydro International Ltd. (MHI) to complete the North Slave Resiliency Study (the "Study") in order to review hydrology and climate change related to the North Slave system, to assess if a new "normal" is emerging or if drought impacts are expected to be periodic, and to examine potential solutions to avoid rate shock or future GNWT subsidies to pay for diesel generation during droughts on the North Slave system.

Overall, energy security today on the North Slave system is very resilient, and this is likely to continue for at least the next 20 years assuming Base Case forecast loads with no additional major industrial load connections. NTPC has enough existing hydro generation capability to supply projected energy requirements under all situations other than drought, emergencies, maintenance overhauls, or other short-term stresses. NTPC's diesel generation capability is sufficient to address these other situations on a cost-effective and reliable basis.

Available information indicates that periodic droughts on the North Slave hydroelectric system have occurred in the past and should continue to be expected in the future. Available information also provides no basis to expect sustained drought today or in the next 10 to 20 years due to climate change. It appears that the drought that lead to this Study began to be alleviated in the fall of 2015, and that GNWT funding requirements are likely to be less than last forecast in mid-2015.

Both temperature and precipitation have increased in the Canadian Arctic over the past 50 years, and an overall warmer and wetter climate is expected in the future. However, there is a large amount of uncertainty regarding climate change impacts to extremes, e.g., the probability of more extreme droughts, the potential for increased inter-annual variability.

Available hydrometric data since 1985 for the Snare and Bluefish catchments is very reliable and is considered adequate to be reasonably representative of a long term period. It is expected that analyses and findings would not be materially different had a longer period or record been used.

The current hydrometric and climate monitoring network is adequate for short-term energy operations and monitoring.

The available information enabled the study team to develop an analytical model that simulates well the general combined operation of the Snare and Bluefish hydro systems, including storage, and to determine potential hydroelectric energy production available on the current North Slave system over the range of water conditions.

The occasional need to use thermal generation to supplement the hydraulic generation due to water availability and also highlights the extent to which actual diesel generation requirements in any year can be driven by factors other than water availability, including actual grid load levels as well as hydro capital works and other "must run" diesel requirements. Actual NTPC hydro operation is also affected by additional factors, including operators' knowledge of infrastructure limitations and constraints related to the supply/demand balance on the grid.

Diesel generation costs due to low water flows or short-term “must run” diesel requirements will not be alleviated today by developing new hydro, wind, solar or other renewable generation. Until there are sustained load increases that far exceed the Base Case forecast, the overall result of new renewable capacity would increase water spilled at the dams and increase electricity rates without materially improving environmental, economy or energy security benefits.

Thermal generation cost changes due to water availability fluctuations are one of the basic cost realities of any hydro system. The adverse impacts from such cost changes can be particularly severe on an isolated hydro system such as the North Slave due to the absence of lower cost options to acquire thermal generation when needed from other jurisdictions. Accordingly, these long term average thermal costs should normally be reflected in rates along with other basic costs required to supply reliable electricity supply.

Recommendations

Possible options to improve North Slave resiliency over the next five to ten years include:

1. **Thermal Generation:** Continued reliance on diesel and/or new natural gas thermal generation to meet any demand that exceeds existing hydro system capabilities is currently the most cost-effective option to ensure reliable performance. This strategy involves:
    a. **Diesel Units:** Ensure that maintenance, rehabilitation and/or replacement of the existing diesel generating units occurs as required to provide operational reliability and extended longevity.

    b. **LNG:** Assess in detail the LNG-supplied thermal generation opportunities to replace end-of-life diesel units, and consider utilizing the resulting LNG supply chain to pursue other opportunities to displace oil product use in the Yellowknife area (including retrofit natural gas/diesel blend options for existing diesel generation units).

2. **Grid Expansion Options:** Assess the feasibility of North Slave grid expansion options to connect industrial (mine) loads and determine if cost and emission savings can result by allowing surplus hydro generation to be used in combination with LNG to displace diesel generation.

3. **Renewable Generation:** Sustain and enhance existing hydro system capability and operation where feasible and assess options and criteria for developing the next new renewable generation capacity. The following are recommended in this regard:

    a. **Bluefish Hydro:** Plan and implement rehabilitation of the Bluefish hydro facility, including considerations for any potential improvement of North Slave system resiliency to drought.

    b. **Additional Snare Hydro Storage Options:** Assess whether cost effective additional storage options for the Snare system can be implemented over the next five to ten years.

    c. **Hydro Operation:** Review hydro operating procedures to ensure that long-term hydro energy is maximized.

    d. **Hydro System Planning Models:** Consider the costs and benefits of developing long-term planning hydro system simulation models that assess long term average thermal generation requirements for different grid loads and the effectiveness of various renewable resource options in displacing expected thermal generation.

4. **Rate Related Resiliency Options:** Rate related resiliency options will remain a key requirement for a hydro-based system such as North Slave, and effective long-term measures are needed to smooth out customer rate instabilities caused by thermal generation cost changes due to changing water conditions. The following are recommended in this regard:

    a. **Rate Stabilization Funds:** Implement rate stabilization measures to smooth out the impact on customer rates of future thermal generation cost changes due to changing water conditions. This includes:

        i. **Rates based on long-term average requirements**: Provide for NTPC revenue requirements for the North Slave to include thermal generation costs for the forecast grid load based on hydro generation assuming long-term average water conditions. This approach will reduce the need to vary rates based on fluctuating short-term water conditions.

        ii. **Dedicated Fund:** Establish a dedicated ratepayer trust fund, with adequate upper and lower caps, to absorb annual variations in actual thermal generation costs compared to the expected long-term average thermal generation cost in customer rates.

b. **GNWT Support:** Inform NTPC and the NWT PUB of any GNWT policy to subsidize NTPC costs due to future North Slave droughts so that this can be fully considered in the planning of rate stabilization measures.

ACRONYMS

AEA	Arctic Energy Alliance
ASL	Above Sea Level
CCCMA	Canadian Centre for Climate Modeling and Analysis
CEATI	Center for Energy Advancement through Innovation
CECEP	Commercial Energy Conservation and Efficiency Program
CORDEX	Coordinated Regional Climate Downscaling Experiment
DCF	Diesel Contingency Fund
DSM	Demand side management
EEIP	Energy Efficiency Incentive Program
FSL	Full supply level
GCM	Global Climate Model
GHG	Greenhouse gas emissions
GNWT	Government of the Northwest Territories
GRA	General Rate Application
GS	Generating system
GW.h/GWh	Gigawatt-hours
IPCC	Intergovernmental Panel on Climate Change
km	kilometers
kW.h	Kilowatt-hours
LED	Light-emitting diode
LNG	Liquefied Natural Gas
LOLE	Loss of load expectation
LSL	Low supply level
LTA	Long-term average
LWRF	Low Water Reserve Fund
MHI	Manitoba Hydro International
MLA	Member of the Legislative Assembly
MSL	Minimum supply level
MW	Megawatt
NOAA	National Oceanic and Atmospheric Administration
NTPC	Northwest Territories Power Corporation
NUL-YK	Northland Utilities (YK) Ltd.
NWT	Northwest Territories
NWTPUB	NWT Public Utilities Board
O&M	Operations and Maintenance
OC	Order in Council
PUB	Public Utilities Board
PV	Present value
RCM	Regional Climate Models
RCP	Representative Concentration Pathways
RFC	Required firm capacity
RSF	Rate stabilization fund
RSP	Rate Stabilization Plan
SREX	Special Report on Extremes
WAF	Whitehorse-Aishihik-Faro
YEC	Yukon Energy Corporation
YUB	Yukon Utilities Board

STUDY PARTICIPANTS

The following firms and individuals were involved in the preparation of the Study.

Manitoba Hydro International

Karim Abdel-Hadi, Project Manager

Ken Adams, Project Expert

Manitoba Hydro

Terry Miles

John Crawford

Kevin Gawne

Reed C. Winstone

Phillip Slota

Kristina Koenig

InterGroup Consultants Ltd

Cam Osler

Patrick Bowman

Hayitbay Mahmudov

Mona Pollitt-Smith

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PREFACE

Recent drought and low water conditions at the Snare and Bluefish hydroelectric facilities dramatically increased diesel generation requirements and costs on the North Slave hydroelectric system.

The GNWT subsequently retained Manitoba Hydro International Ltd. (MHI) to complete the North Slave Resiliency Study (the "Study") in order to review hydrology and climate change related to the North Slave system, to assess if a new "normal" is emerging or if drought impacts are expected to be periodic, and to examine potential solutions to avoid rate shock or future GNWT subsidies to pay for diesel generation during droughts on the North Slave system.

The MHI study team has completed the following Final Report which provides analysis of the existing North Slave hydro generation system capability and the options available to improve its resiliency.

Study Objectives

NTPC supplies electricity to its customers in the North Slave region over an isolated transmission grid powered by the Snare and Bluefish hydroelectric systems and the Jackfish diesel generation plant located at Yellowknife.

Available information was used to identify options that could be pursued over a 5 to 10 year horizon to reduce the cost of power supply to the North Slave region, reduce the supply risks or cost instability associated with droughts, and increase the reliability of the generation/ transmission system. The Study focuses on three primary areas:

1) Examine existing hydrology trends in the North Slave region and consider options for implementing enhanced monitoring tools and forecasting models;
2) Identify and evaluate a range of infrastructure options that can be developed to improve the North Slave system's resiliency to periodic droughts; and
3) Analyze the electricity rate structure options in order to avoid rate shock when future droughts occur.

Overview of Work to Date

The MHI study team completed the following background reviews pursuant to the Final Work Plan as approved in October 2015:

1) Reference Point - System Loads & Generation - Next 10 to 20 Years (Attachment 1);
2) Hydrological Background & Assessment (Attachment 2);

3) Infrastructure Options Background (Attachment 3); and
4) Rate Structure & Non-Infrastructure Options Background (Attachment 4).

Outline of Report

In addition to the Executive Summary, the Final Report provides a more detailed summary of the study team's analysis in two parts:

1. Part 1: North Slave Hydro Generation Capability (review of potential hydro generation production capability simulated for the existing North Slave hydro system, and related North Slave diesel generation requirements reflecting the impacts of water availability and other factors); and
2. Part 2: Review of Resiliency Options (review of infrastructure and non-infrastructure options available to improve the resiliency of the North Slave system).

1.0 PART 1: NORTH SLAVE HYDRO GENERATION CAPABILITY

Part 1 reviews the North Slave hydrology and system characteristics, potential hydro generation production capability simulated for the existing North Slave hydro system, and the existing diesel generation requirements that result at various system loads based on water availability and other factors. The following are addressed:

- North Slave Hydrology and System Characteristics
- Maximized Hydro Simulation
- Diesel Generation - Impacts of Water Availability and Other Factors
- Basis for Current GNWT Low Water Funding Contribution Estimate
- Summary - North Slave Hydro Generation Current Capability

1.1 NORTH SLAVE HYDROLOGY AND SYSTEM CHARACTERISTICS

Existing North Slave hydro generation capability is located on two separate hydro systems: the Snare system with approximately 29 MW generating capacity, and the Bluefish system with approximately 7 MW generating capacity. Each hydro system has a relatively small catchment area.

Figure 1 summarizes inflows from 1950 to 2015 to the Big Spruce reservoir upstream of the Snare system hydro generation facilities, which account for 80% of the North Slave hydro capacity.[1] Figure 1 highlights three different time periods regarding this water record:

- The 1985-2014 period of 30 years. This period has excellent Snare daily flow data from Water Survey of Canada, and includes what appears (from Figure 1) to be the extreme high (1996) and the second lowest (2014) flow over a much longer period of time[2]. The data from this time period was used for the simulation study described in Attachment 2, as reviewed below.
- The 1950-1984 period of 35 years with less reliable hydrologic data. It is observed in Attachment 2 that significant and unexplainable errors regarding this earlier part of the record have been noted in past studies, and therefore this data was not used in the Study's simulation. The water records available for this period indicate a prolonged period of low

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[1] Figure 1 shows annual monthly mean inflows (m^3/s) to the Big Spruce reservoir. Monthly mean flow information is based on Big Spruce Lake mean monthly inflows from 1950 to 2013; and NTPC's Snare System level and flow data for 2014 and 2015.

[2] The 2014 annual mean monthly flow (25.3 m^3/s) was only slightly above the lowest flow shown in Figure, i.e., the 1981 flow (24.6 m^3/s).

flows immediately prior to 1985 and the period of good records. These earlier records also indicate no floods over this earlier period, which is unlikely to be accurate.

- The year 2015 is shown separately. This reliable data was not available at the time of the simulation. As reviewed later, NTPC hydro generation data for 2015 into early December (adjusted for plant availability) was used in order to consider the impacts in 2015 of the recent drought.

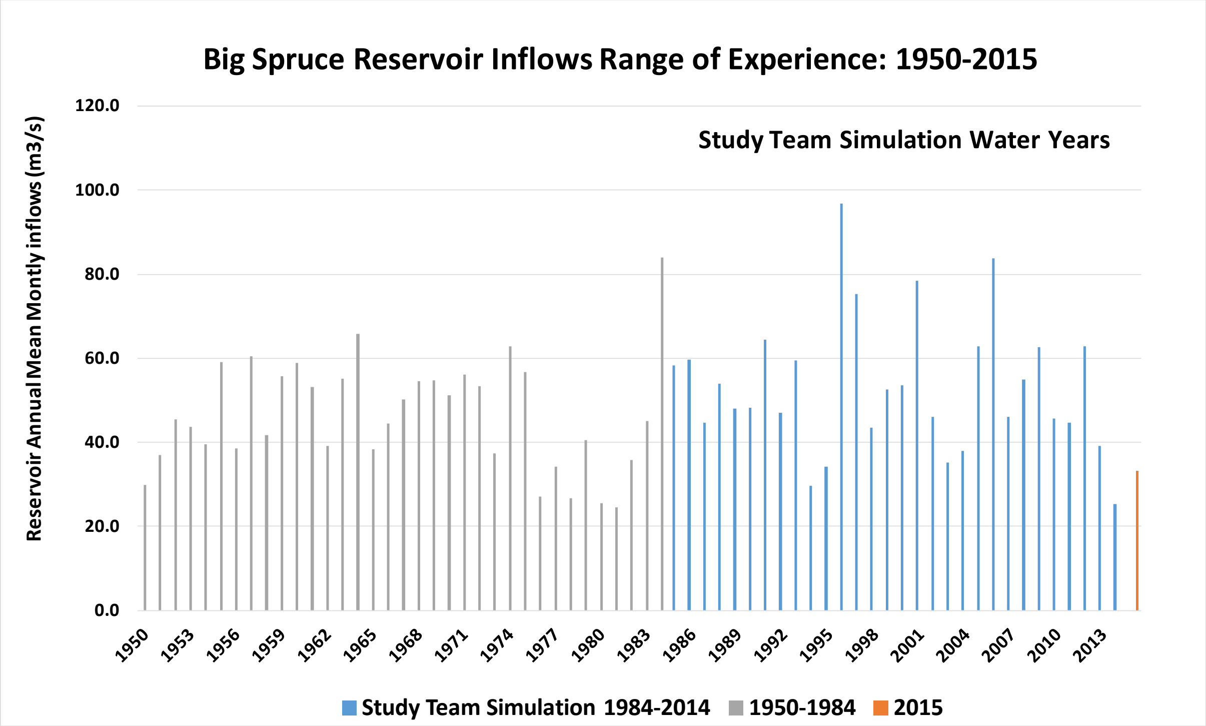

Figure 1: Annual Monthly Mean Inflows Big Spruce Reservoir for Snare System: 1950-2015

The study team's review of hydrology and system characteristics for the North Slave's existing hydro generation facilities concluded (see Attachment 2) that:

- Thirty years (1985 to 2014) of good quality, daily hydrometric data are available for the Snare and Bluefish catchments. This is adequate to be reasonably representative of a long term period; it is expected that analyses and findings would not be materially different had a longer period or record been used.[3]

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[3] As noted earlier, the water record data for the full 2015 was not available at the time of the Attachment 2 review - however, as reviewed in the following section, the MHI study team has utilized NTPC hydro generation data in 2015 into early December (adjusted for plant availability) in order to consider the impacts in 2015 of the recent drought.

- The current hydrometric and climate monitoring network is adequate for short-term energy operations and planning.
- The available information enabled an analytical model to be developed that simulates very well the general combined operation of the Snare and Bluefish hydro systems, including storage. This model was used to determine potential hydroelectric energy production available to the North Slave system, i.e., its maximized hydro generation capability, over the range of water conditions between 1985 and the end of 2014.
- Both temperature and precipitation have increased in the Canadian Arctic over the past 50 years, and an overall warmer and wetter climate is expected in the future with an earlier spring melt. However, there is a large amount of uncertainty regarding climate change impacts to extremes, e.g., the probability of more extreme droughts, the potential for increased inter-annual variability.
- Review of literature found a significant amount of relevant paleontological material in the North Slave region study area, none of which appears to have been analyzed with respect to long-term streamflow variability and persistence. It is likely that when this material is analyzed, it will probably show both wetter and dryer periods than the Figure 1 water record. It was noted by the GNWT that some of the paleoclimatology work that has been performed in this area is currently being summarized. However this work requires further research.

Based on the review by the study team, analysis of North Slave hydro generation capability in the following sections focuses on the water record from 1985 to 2015. During this period, Figure 1 highlights low water conditions (i.e., Big Spruce annual average mean monthly flows less than 40 m^3/s) in 1994 and 1995, 2003 and 2004, and 2013 to 2015.

Figure 2 shows the Big Spruce monthly mean flows over this period, highlighting the last three years with the recent drought. The Big Spruce reservoir generally starts filling in the early summer and into the fall. However, due to drought conditions, this did not happen in 2014 and 2015 as indicated in Figure 2.

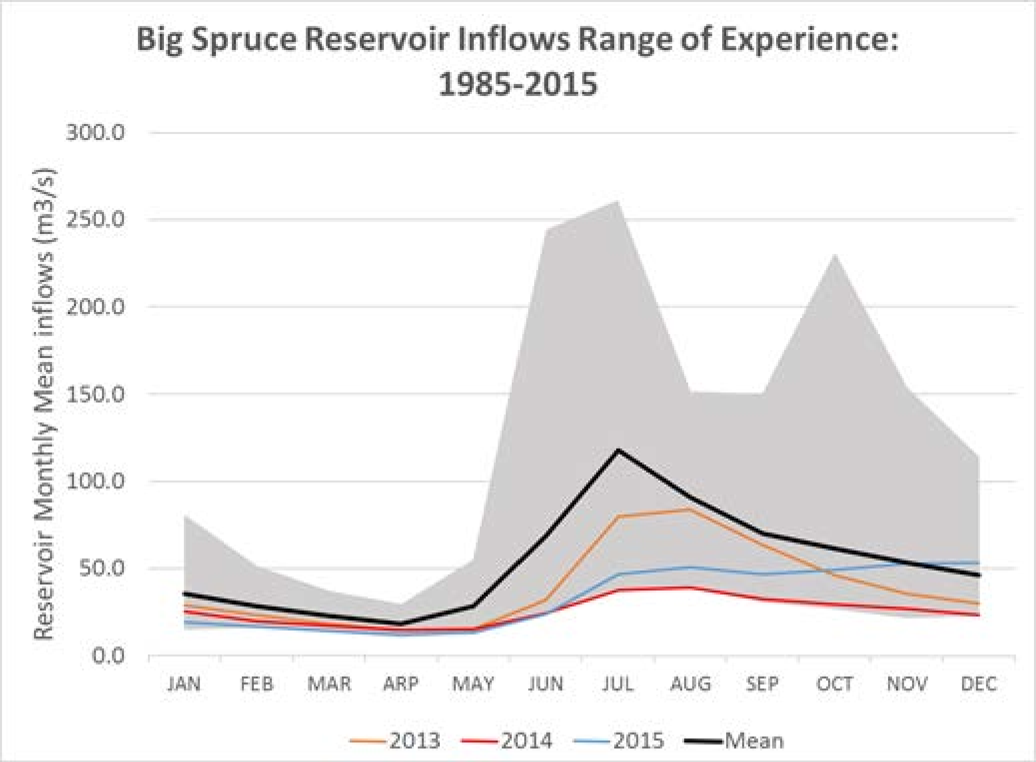

Figure 2: Monthly Mean Inflows Big Spruce Reservoir for Snare System: 1985-2015

While focusing on the period since 1985, it is worth noting that Figure 1 indicates for earlier years a long period of low flows from 1976 to 1982, as well as other earlier years with low flows in 1950 and 1951, 1962 and 1973.

1.2 MAXIMIZED HYDRO SIMULATION

Maximized hydro generation capability for the North Slave system has been assessed in this section without considering limitations due to existing loads or a range of other practical operating conditions which are reviewed in Section 1.3.

The simulation model (see Attachment 2) estimated the potential hydroelectric energy production available for each day to the North Slave system, i.e., its "maximized hydro generation capability", based upon existing hydro facilities and water flows available on the Snare and Bluefish systems between 1985 and 2014.

The simulation estimates the "maximum potential hydro energy generation available". This means that it does not consider whether the energy is usable on each day, forced or planned maintenance outages, must-run diesel operations, operators' detailed knowledge of short term generating equipment limitations or detailed constraints related to the supply/demand balance on the grid. Such models are best described as Decision Support Systems. They can assist System Operators, but cannot replace the knowledge and skills of the people who must make informed decisions in real time, often on the basis of incomplete information and with competing objectives. Similarly, they can assist planners to evaluate courses of action; however, they cannot be considered as 'predictive'. The more sophisticated models can be used to calculate probabilities based on previous experiences, but cannot determine whether past experiences will be repeated in the future nor what future events will be. Models are best used to explore different future scenarios developed by the analyst, i.e., to explore 'what happens if...?'

Figure 3 shows maximized hydro generation for the overall North Slave system by month from January to December during the period from 1985 to 2015, highlighting how this hydro generation capability varies in response to changing water conditions.

The shaded area of Figure 3 shows the range and 30-year average for monthly hydro generation capability based on the 30-year water record from 1985-2014 that was relied upon for the simulation in Attachment 2. It also shows the simulation for each of the five lowest water years during this period (in order from lowest to highest: 1995, 2014, 2004, 1994 and 1996). Maximum potential 2015 generation, which was not included in the simulation, is shown separately in Figure 3 as a separate line that goes below the shaded area from June to October.

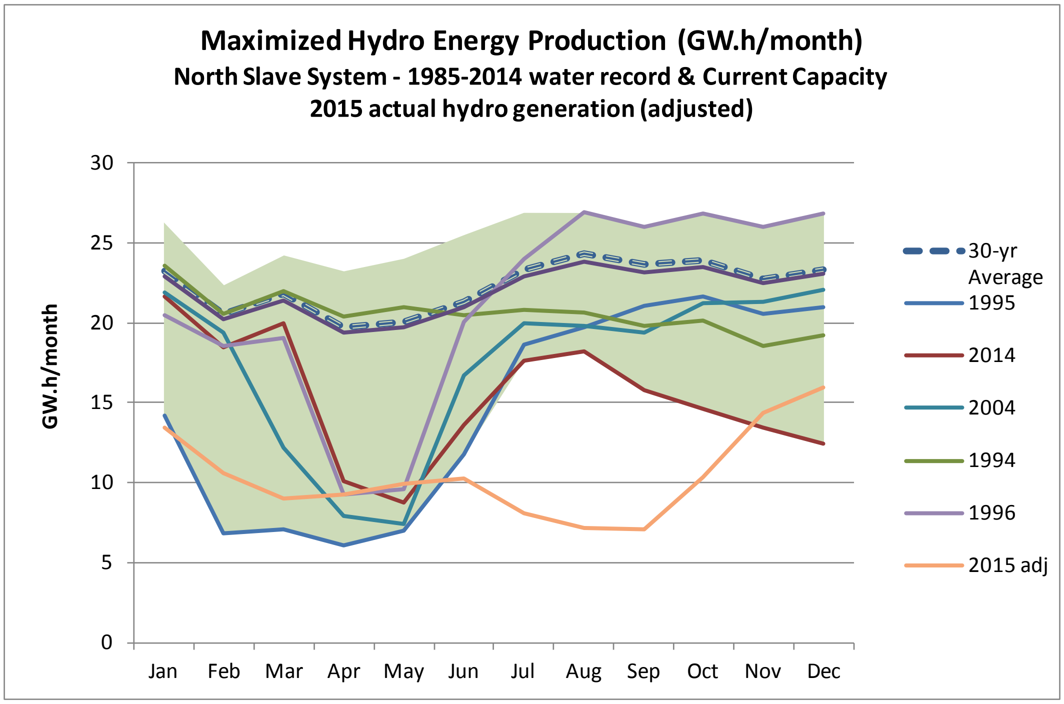

Figure 3: North Slave Maximized Annual Hydro Generation by Month: 1985-2015

Maximum potential 2015 generation in Figure 3 is an estimate prepared in mid-December 2015 based on actual hydro generation for the first 11 months (adjusted to remove impacts from a major overhaul[4]) plus the latest forecast generation for December[5]. This 2015 information was not available for the simulation assessment in Attachment 2, and is provided to illustrate more fully the recent range of water conditions and related diesel generation. Due to the very low water conditions in 2014 and through the first half of 2015 and the operation of material diesel generation in each month of 2015, the adjusted hydro generation as shown in Figure 3 is assumed to reasonably approximate the 2015 maximized hydro generation capability for the year based on the 2014 and 2015 actual water conditions. The distribution of 2015 diesel generation by month after June, however, does not fully reflect the Snare inflow improvements shown in Figure 2, i.e., it indicates operator focus during July through September on improving Big Spruce reservoir levels above the low supply level as well as very low inflows for the Bluefish system throughout all of 2015.

Figure 3 demonstrates the following features of the current North Slave hydro system:

- The simulated 30-year average monthly maximized hydro generation remains relatively flat over the year, ranging from 19.7 GW.h in April to 24.3 GW.h in August.
- Between January and May, the simulation produced below average monthly generation in less than 10 of the 30 water years, with five of these years being particularly noticeable.
- Between June and December, below average monthly generation occurred between 9 and 13 of the 30 simulated water years. Figure 3 highlights five of these years, and that 2014 after about August was very unlike any of the other 30 years.
- Most water years during the 30 years of simulation show maximized hydro generation that exceeds the average, but without the extreme variances that are shown within the low water years. This reflects the limits to which existing hydro generation capacity can utilize flows that are well above the long-term average.
- The available 2015 generation provided in Figure 3 (and not included in the 30-year simulation for 1985 to 2014) shows a year unlike any of the others, with hydro generation low throughout the year and below other years from June to October.

In summary, the 30-year maximized hydro simulation for 1985-2014 presented in Figure 3 shows a 30-year long-term average (LTA) maximum hydro production capability of approximately 268

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[4] The 2015 data was adjusted from May to end of the year to compensate for the diesel generation that was required due to a major overhaul of the Snare Falls Hydro Unit.

[5] Subsequent review in February 2016 indicated small adjustments applicable to the year end generation numbers which would not materially affect the analysis developed earlier based on the mid-December 2015 estimates.

GW.h/year, comprising 215 GW.h/year from the Snare system and 53 GW.h/year from the Bluefish system. If the 2015 actual hydro generation (adjusted) as shown in Figure 2 is included, the 31-year LTA maximum hydro production capability is approximately 263 GW.h/year.

Figure 4 below shows maximized annual hydro generation between 1985 and 2015 with data arranged from lowest to highest maximized annual hydro generation. Maximized annual hydro generation for each of the 31 years of water record used (organized by year) is provided in Appendix A (see Table A-1 and Figure A-1).

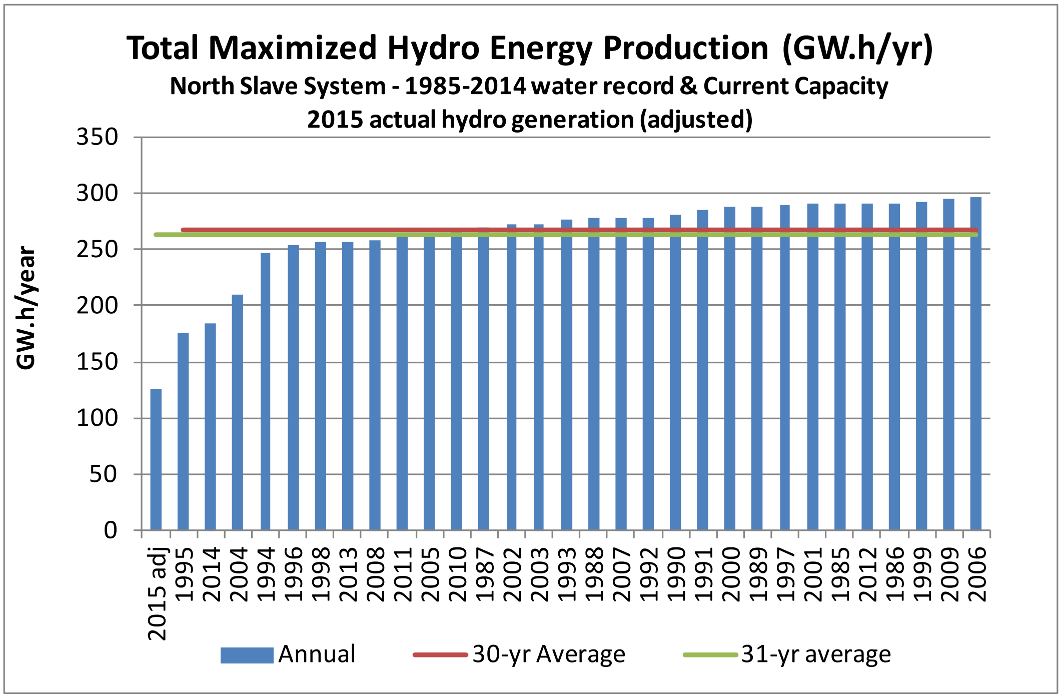

Figure 4: North Slave Maximized Annual Hydro Generation by Water Year: 1985-2015

In summary, Figures 4 highlights the following:

- In most years maximum potential hydro generation exceeds the 31-year LTA of 263 GW.h/year from 1985 to 2015. i.e., maximum generation exceeds this LTA in 22 of these 31 water years, and is less than this LTA in only 9 of these water years; and
- Low water conditions drop the maximum annual hydro generation capability below 210 GW.h/year (80% of the LTA) in three periods between 1985 and 2015 (2014 and 2015, 1995, and 2004).

The 125 GW.h of maximum hydro generation capability for 2015 due to low water conditions included 111.7 GW.h for the Snare system and 13.5 GW.h for the Bluefish system. Overall, the 2015 generation was about 30% below maximum hydro generation for any other water year since 1985 - but is likely not unprecedented based on water years since 1950. Figure 1 at the outset of Part 1 indicates that similar low water levels were encountered on the Snare system for several years between 1976 and 1982. The quality of water records for this earlier period did not enable the MHI study team to include these water years in its simulation conducted in Attachment 2 for the Study.

The 2015 low level of maximum hydro generation capability reflected low water conditions in the prior year (which reduced storage), lower inflows in 2015 than 2014 on the Snare system until after May (and Snare inflows not exceeding average until November/December), and extreme low inflows on the Bluefish system throughout 2015. Potential maximum hydro generation for 2015 was estimated based on actual generation for 11 months, adjusted for Snare Falls Hydro major overhaul. Despite Snare inflows to Big Spruce reservoir starting to improve in July, actual Snare hydro generation was kept low through September in order to build water in the reservoir back up above regulated low supply levels.

Figure 5 illustrates the existing North Slave system's annual total maximized hydro output, showing duration curves for annual maximum energy production available over 30 years (1985-2014) and 31 years (1985-2015) of water record. Figure 5 is based on the annual maximum hydro generation for each year as shown in Table A-1 in Appendix A, with this information arranged as in Figure A-1 in Appendix A. The duration curve for 31 years shows the percent of the 31 water years that potential maximum hydro generation is not less than the specified level, e.g., for 3.2 % of these years [1 year] it is not less than 125 GW.h/year, for 6.5% of these years [2 years] it is not less than 175 GW.h/year, etc.

Figure 5 also compares these maximum hydro energy duration curves with two example generation load levels for the North Slave: 195 GW.h/year (an approximation of current system generation loads) and 255 GW.h/year (higher loads that tended to be the minimums experienced prior 2004/05 when two operating mines were connected to this grid).

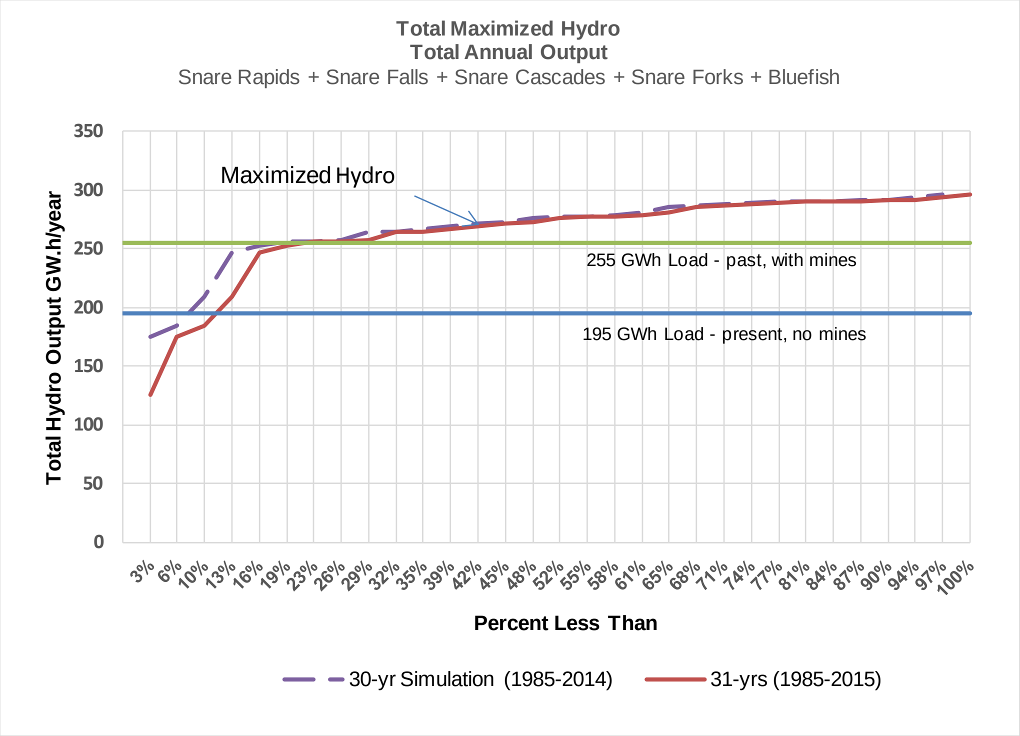

Figure 5: North Slave Annual Hydro Generation: Maximized Hydro (1985-2015)

Figure 5 reflects a relatively short 31-year period of reliable water record and the maximum potential hydro output without accounting for various other "non-water supply" factors that may affect hydro output in any year. Notwithstanding such factors, which include outages, maintenance, capital work, operating practices to manage system risks, and load limitations:

- Maximized North Slave system hydro generation for most water years is well above the North Slave system's 190 to 195 GW.h/year loads over the last two years, and also exceeds the 255 GW.h/year grid loads experienced earlier when two operating mines were connected.

- Based on these maximized hydro output estimates, diesel generation for energy is needed in about 11% of the 31 water years at an annual load of 195 GW.h, and in about 21% of the 31-year water years at the higher annual load of 255 GW.h.

- The existing North Slave hydro system could produce at potential maximum output levels of at least 275 GW.h/year for 50% of this 31-year water record; this minimum hydro capability approximates at least 245 GW.h/year for about 84% of the 31 water years, and about 175 GW.h/year for about 94% of the 31 water years.

1.3 DIESEL GENERATION - IMPACTS OF WATER AVAILABILITY AND OTHER FACTORS

"Maximized hydro" as shown in Figures 1 through 5 assumes that sufficient load exists to utilize all of the available hydro generation throughout the year, and ignores any interruptions due to outages, capital works or other factors. Based on these assumptions an approximate minimum total diesel requirement can be estimated at any assumed load for each of the 31 water years (1985 to 2015)[6]:

- At an assumed load of 195 GW.h/year, the minimum **total** diesel generation requirement over 31 water years would approximate 100 GW.h (80 GW.h over the 2014 and 2015 water years plus 20 GW.h for the 1995 water year); an annual long-term average (LTA) minimum diesel generation requirement can then be estimated at about 3.2 GW.h/year (100 GW.h/31 water years).
- At an assumed load of 255 GW.h/year, the minimum **total** diesel generation requirement over 31 water years would approximate 335 GW.h, indicating an annual LTA minimum diesel generation requirement of about 10.8 GW.h/year.

In practice, however, the North Slave hydro system is subject to major changes in load and various other factors affecting diesel generation and many of these factors will continue to influence future requirements for thermally based generation.

Figure 6 illustrates the extent to which annual North Slave diesel generation and water availability on the Snare system have each varied since the 1994/95 fiscal year, with 2015/16 based on eight months of actual and four months of NTPC forecast data (see Attachment 1)[7]. Three periods of low water (i.e., less than 40 m^3/s annual mean monthly flow) are highlighted over this 22-year period (1994 and 1995, 2003 and 2004, and 2013 to 2015).

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[6] See Appendix A, Table A-1 which shows maximum hydro generation for each water year, e.g., 125.3 GW.h in 2015 water year, 184.6 GW.h in 2014 water year and 175.4 GW.h in 1995 water year.

[7] Subsequent review in February 2016 indicated small reductions applicable to the actual diesel generation for July and the final amount for December, as well as reduced forecast diesel for the balance of the fiscal year. These adjustments would not materially affect the analysis developed earlier based on the mid-December 2015 estimates.

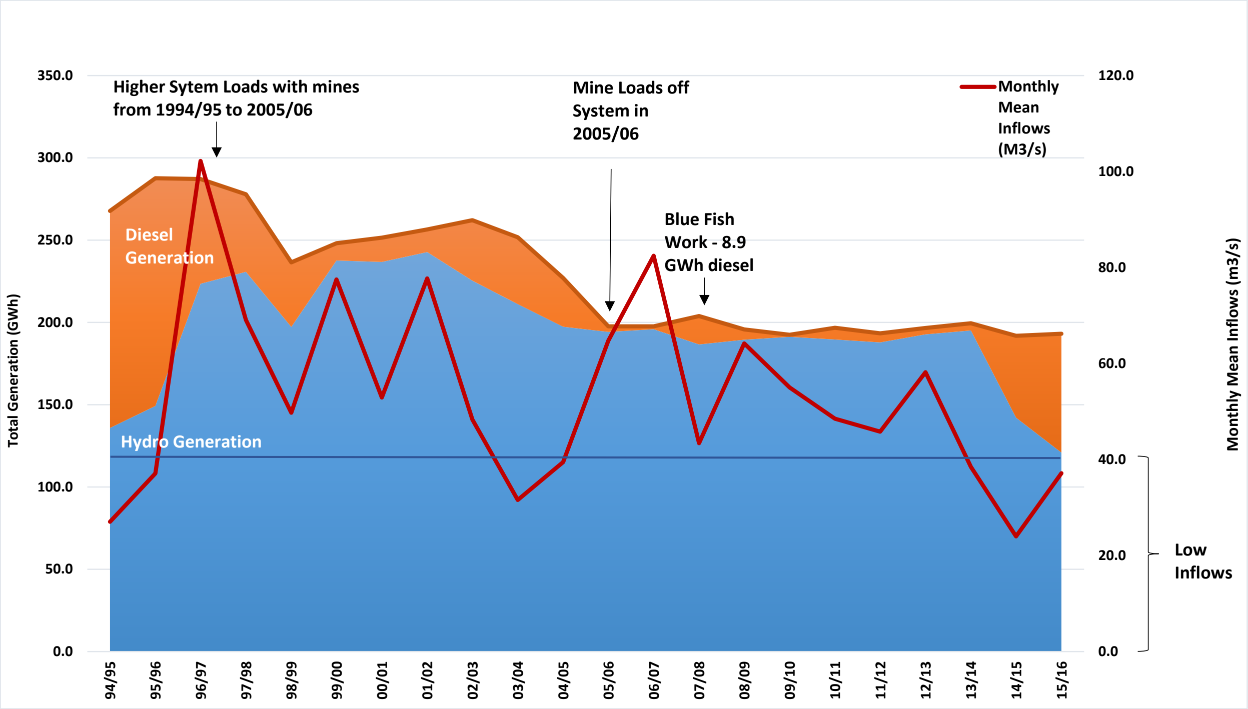

Figure 6: North Slave Diesel Generation & Big Spruce Mean Monthly Inflows: 1994/95 to 2015/16

Figure 6 shows that demand for diesel generation can be driven by factors other than water availability. Two such factors can be highlighted:

- **Total Grid Load Levels:** Diesel generation requirements can vary with total grid load levels:
    - Between 1994 and 2004, operational mines connected to this hydro grid resulted in annual generation requirements ranging from 236.5 GW.h (1998/99) to 287.6 GW.h (1995/96), and exceeding 251 GW.h in eight of the ten years. Annual diesel generation over these 10 years ranged from 10.5 to 138.4 GW.h, exceeding 35 GW.h/year in seven of the ten years.
    - In contrast, between 2005/06 and 2015/16 no operational mines were connected to this hydro grid. Annual generation requirements ranged from 191.9 GW.h (2014/15) to 203.9 GW.h (2007/08), and were less than 197.7 GW.h in nine of the 11 years. Annual diesel generation over these 11 years ranged from 1.3 to a forecast 72.3 GW.h, and was below 7.5 GW.h/year in eight of these eleven years (see below for factors other than load in two of the remaining three years).

- **Hydro Capital Work and other "Must Run" Diesel Requirements:** Similarly, demand for diesel generation can vary due to hydro capital works and other "must run" diesel requirements:
  - Diesel generation demand jumped to 17.2 GW.h in 2007/08 when mines were not operational and total generation was only 203.9 GW.h. Available information indicates that about 85% of this diesel generation was due to Bluefish facility capital work (which accounted for 8.9 GW.h of diesel generation), maintenance (4.6 GW.h of diesel generation), outages (0.4 GW.h) and diesel engine exercising (0.5 GW.h). The balance of 2.6 GW.h of diesel generation was due to system operation in a year when there was ample water availability (Table A-1 in Appendix A indicates maximum hydro capability in excess of 250 GW.h in 2007 and 2008).
  - Diesel generation demand jumped to 72.3 GW.h in 2015/16, with 22.8 GW.h due to an overhaul of the Snare Falls Hydro Unit (the balance of 49.5 GW.h is forecast to be required due to low water).

Actual NTPC hydro operation is also affected by factors beyond those reflected in the maximized hydro output simulation or the "must run" diesel generation that is not related to water conditions. In particular, the NTPC operators' knowledge of infrastructure limitations and constraints related to the supply/demand balance on the grid can lead them not to operate at potential maximum hydro production when faced with situations such as the following[8]:

- The existing Snare Rapids spillway design creates a situation in which operators may be unable to pass water when the reservoir reaches its low supply level (LSL) and the 8 MW generating unit is inoperable. This would so severely impact downstream Snare system hydro power capability that NTPC operators try to prevent extended Snare operation at the regulated LSL. They do this by reducing hydro generation and running diesel generation as water levels approach the LSL instead of simply maximizing hydro until water levels reach the LSL (as assumed in the maximized hydro generation simulation).
- Similarly, the Snare Rapids spillway may be inaccessible during periods of bad weather, thereby making it impossible to spill water as required during full supply level (FSL) scenarios. Operators in some situations therefore prevent extended Snare operation at the regulated FSL by, prior to reaching FSL, spilling water that would ideally be retained for

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[8] Personal communication with Dan Grabke, December 2015. See also NTPC March 30, 2015 report: "Snare System Medium to Longer Term Resource Planning and Drought Management" at page 3 where the need is noted for ongoing generation mix optimization considering the balance between two types of operating risk: risk of loss of supply if stored water is drawn down and low water conditions persist (i.e., risk of not being able to meet the demand during high consumption periods in winter), and the risk of water spilling (i.e., if store water in summer under extreme low water conditions to provide for peak winter loads, this stored water may lead to spilling if there is significant rainfall in summer and fall).

later use. This can result in needing to run diesel generators in subsequent periods not predicted in the maximized hydro output simulation.

- Hydro turbines must be operated during extreme cold weather conditions in order to prevent their freezing. Under low water conditions, operators may therefore elect to save water in the late fall (so that it is assured to be available during extreme cold weather) rather than operating at the maximized hydro output.
- Concerns about the reliability of NTPC's aging diesel units lead operators to run the diesel units in a way that minimizes their "stop/start" cycling instead of optimizing diesel consumption, as assumed in the maximized hydro output simulation. Similarly, diesel generator reliability concerns can lead operators to conserve water (rather than use it as soon as there is opportunity to displace diesel generation, as assumed for maximized hydro output) to ensure reliable hydro capability during peak winter hours.[9]

Table 1 summarizes the factors accounting for the 128.7 GW.h of North Slave diesel generation between 2011 and 2015 (calendar years). [10]

Based on Table 1, Figure 7 shows for each year the "must run" diesel generation that is specifically estimated for specific requirements that are not water-related. Figure 8 shows the total diesel generation each year, broken into "must run" diesel generation and the balance which is assumed to be diesel generation required due to water conditions. Figures 7 and 8 both show, for contrast, the amount (1.2 GW.h/year) for diesel generation that is actually included in rates. "Must-run" diesel generation exceeded this amount in each of the five years, before low water diesel generation is considered.[11]

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[9] Reliability concerns regarding diesel generators can be accentuated if, due to drought, unanticipated and extended operation of aging diesel generator units accelerates the timing for required maintenance and major overhaul of stand-by diesel generation units.

[10] The 2015 diesel generation is based on estimates prepared in mid-December 2015. Subsequent review in February 2016 indicated small reductions applicable to the actual diesel generation for July and the final amount for December, i.e., the final 2015 total diesel generation was 81.9 GW.h versus the 84.8 GW.h estimate in Table 1. These adjustments would not materially affect the analysis developed earlier based on the mid-December 2015 estimates (the adjustment does not change "must run" diesel for 2015 as estimated in Table 1).

[11] Portions of "must run" diesel generation costs will be capitalized (as part of major overhauls) or recovered through insurance or other similar provisions.

Calendar Year	Total Diesel Generation (GWh)	Notes re: factors accounting for diesel generation	Must-Run Diesel Generation (not water-related) (GWh)	Balance - Diesel Generation due to Water Conditions (GWh)
2011	2.4	0.5 GWh. planned/unplanned maint.; 0.2 GWh outages; 0.8 GWh weather (thunderstorms); 0.06 GWh exercizing	1.6	0.8
2012	6.7	3.8 GWh when helicopter struck Snare transmission (outage Feb 14 to Feb 23 - not charged to stab fund); 1 GWh planned/unplanned maint.; 0.2 GWh outages; 1.5 GWh fixing Bluefish line; 0.07 GWh exercizing	6.6	0.2
2013	4.4	0.45 GWh outages; 2.8 GWh planned/unplanned maint.; 0.2 GWh exercizing; 0.4 GWh cold weather	3.9	0.4
2014	30.5	0.5 GWh outages; 2.0 GWh planned/unplanned maint.; 0.2 GWh exercizing; 0.2 GWh cold weather; 1.1 GWh fire;	4.0	26.5
Total	**43.9**		**16.0**	**27.9**
4 yr. Av/year	**11.0**		**4.0**	**7.0**
2015	84.8	19.8 GW.h Snare Falls overhaul	19.8	65.0
Total	**128.7**		**35.8**	**92.9**
5 yr. Av/year	**25.7**		**7.2**	**18.6**

Table 1: North Slave diesel generation: 2011 to 2015 (calendar years)

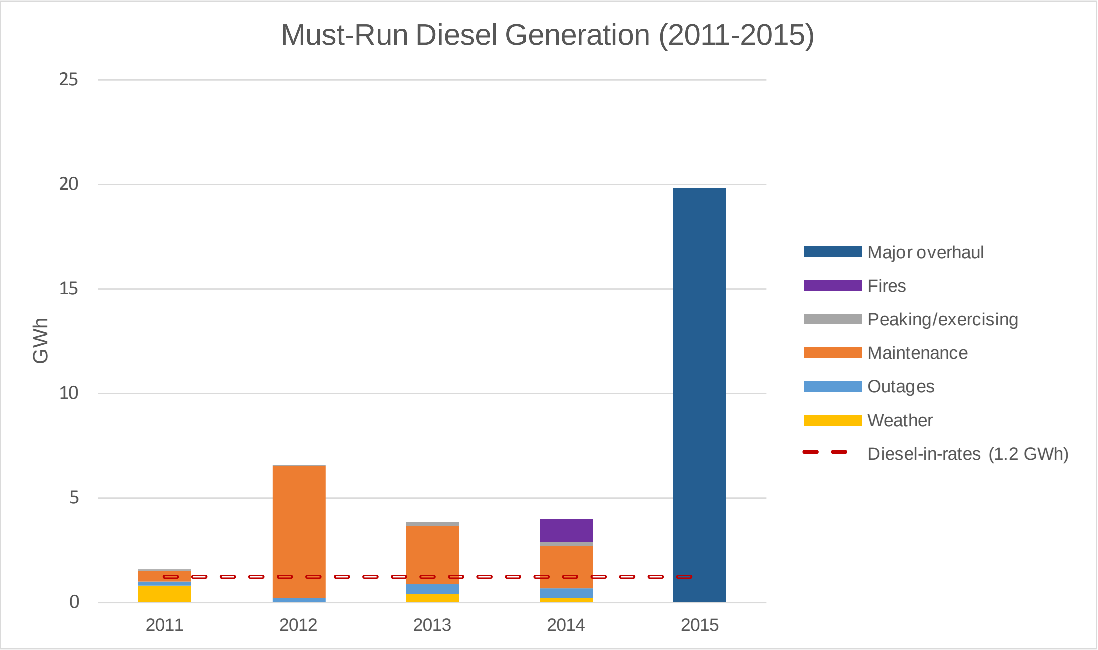

Figure 7: North Slave Must-Run Diesel Generation: 2011-2015 (calendar years)

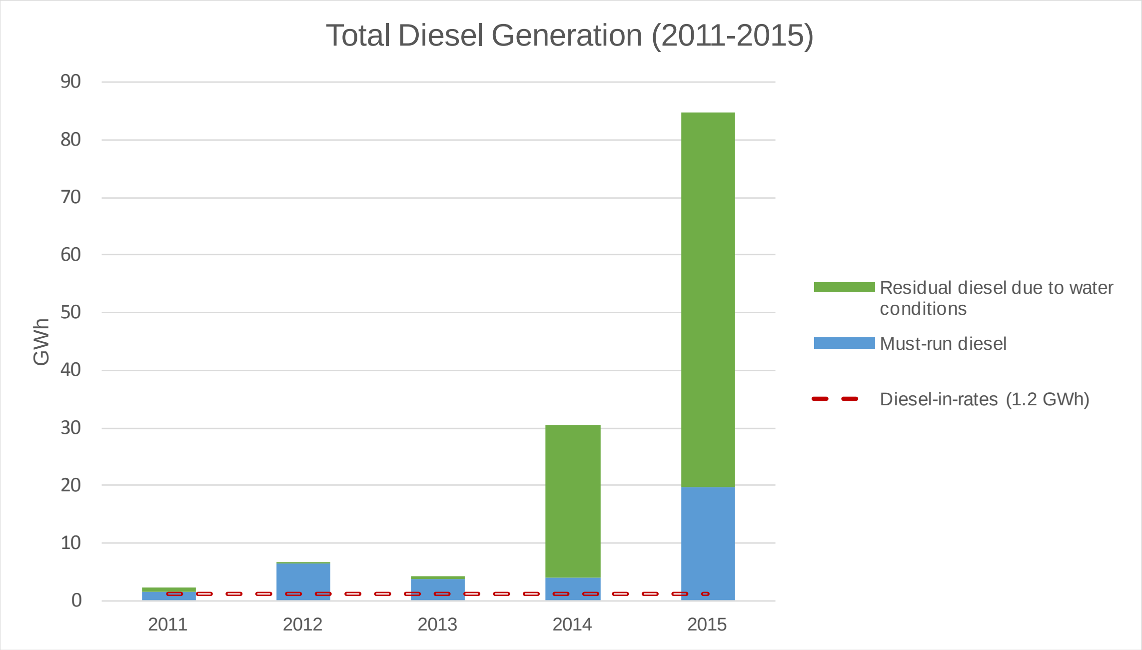

Figure 8: North Slave Total Diesel Generation: 2011-2015 (calendar years)

One dramatic example of a "must run" diesel generation situation is the helicopter strike in February 2012 that caused an outage on all Snare units, accounting for the lowest level of observed daily hydro output during this period and 3.8 GW.h of "must-run" diesel generation.

Overall, 35.8 GW.h of diesel generation was required over the five years as a result of “must-run” diesel generation factors that were not water-related such as outages, major overhaul, maintenance, unit exercising, and weather.[12] The remaining 92.9 GW.h of diesel generation is assumed to be due to water availability (almost entirely related to 26.5 GW.h of diesel in 2014 and 65.0 GW.h in 2015 due to low water conditions).

Over the five-year period between 2011 and 2015, "must-run" diesel generation due to factors described in Table 1 as not water-related averages 7.2 GW.h/year. The balance of the diesel generation during this period averages 18.6 GW.h/year, and is assumed in Table 1 to be due to water conditions.

As reviewed earlier, operator decisions to deal with various limitations and constraints beyond “must run” diesel requirements may result in more diesel generation than expected based on the

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[12] "Must run" diesel generation in these cases during periods of ample water availability (e.g., between 2011 and 2013) occurs when ability to use hydro generation is constrained by factors other than water availability. "Must run" diesel generation can also occur during a drought period, e.g., in 2015 the Snare Falls Hydro Unit overhaul eliminated the potential for hydro generation that would otherwise have occurred given the available water.

potential maximized diesel generation. Between 2011 and 2014, actual diesel generation as reviewed in Table 1 was approximately 5 GW.h more than diesel generation requirement based on the simulated maximized hydro generation by month for these water conditions.[13] It is not feasible in this Study to delineate specific factors responsible for this variance.

1.4 BASIS FOR CURRENT GNWT LOW WATER FUNDING CONTRIBUTION ESTIMATE

Table 2 summarizes earlier and updated diesel generation forecasts and costs assumed for GNWT's commitments in 2014 and 2015 to contribute up to $48.6 million related to additional diesel generation due to low water levels during 2014 to 2016 on the North Slave system.

The GNWT commitment limit of $48.6 million was based on mid-2015 estimates. It applied to actual fuel and lube costs for all diesel generation exceeding 1.2 GW.h/year (assumed allowance for diesel not related to low water) from April 2014 to July 2016. Table 1 for 2014 and 2015 highlights the extent to which this commitment for at least these years includes material "must run" diesel generation that is unrelated to low water conditions. Approximately 61% of this mid-2015 estimate was based on forecasts for diesel generation costs after June 2015 (accounts for 106 GW.h, or 62% of the total low water diesel generation in Table 2 under the mid-2015 estimates).

Updated diesel generation for 2015 as shown in Table 1 indicates lower diesel generation for 2015 relative to the Table 2 forecast provided in mid-2015. Table 2 provides updates as of February 2016 regarding the low water impacts on diesel generation and GNWT funding requirements. Reflecting improved Snare water inflows starting in mid-2015 as well as the catchment area snow water equivalent estimates as of January 2016 (which show major improvements from the same month in the previous two years), the updated estimates reduce the expected three year diesel generation impact by 51.5 GW.h.[14] The current estimate for the GNWT funding is $29.1 million, a reduction of $19.5 million from the earlier estimate. Some of the reduction in funding requirement also reflects lower diesel fuel costs (i.e., costs per litre, as reflected in costs per kW.h) in 2015 and 2016 compared to prior estimates.

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[13] This estimate reflects month-by-month comparison in 2014 of actual grid load, maximized hydro as simulated, actual hydro plus "must-run" diesel, and the balance of actual diesel generation. Simple comparison of Table A-1 maximized hydro for 2014 (184.6 GW.h) and actual grid load (195.2 GW.h) would suggest that diesel due to water availability for 2014 would be only 10.7 GW.h rather than the actual 26.5 GW.h (a gap of 15.9 GW.h); however, months when maximized hydro exceeds grid load (and is therefore not able to displace diesel) reduces the effective maximized hydro generation by 12.2 GW.h. Table 1 also estimates for 2011-2013 approximately 1.2 GW.h of "diesel generation due to water conditions" in years when maximized hydro estimates would not indicate any need for such diesel generation.

[14] Diesel generation in 2015 is 4.8 GW.h lower in Table 2 than in Table 1; this reflects final diesel generation as currently estimated for 2015 (81.9 GW.h) less 1.2 GW.h for diesel generation included in rates for 2015/16.

GNWT Contribution Commitments to North Slave Low Water Costs

	Estimate as at mid-2015			Update Feb 2016		
Calendar Year[2]	Low Water Diesel[1] (GW.h)	Cost per kW.h[3] ($/kW.h)	GNWT Contribution[4] ($million)	Low Water Diesel[1] (GW.h)	Cost per kW.h[3] ($/kW.h)	GNWT Contribution[4] ($million)
2014	28.37	0.311	8.82	28.37	0.311	8.82
2015	89.88	0.281	25.25	80.04	0.230	18.44
2016	51.85	0.280	14.52	10.19	0.184	1.87
Total	170.10	0.286	48.59	118.60	0.246	29.13

Notes:
1 Diesel generation above 1.2 GW.h/yr from April 2014 to July 2016.
2 GNWT funds from April 2014 to July 2016.
3 "Actual" diesel generation and lube cost (based on actual/approved plant efficiency and actual/GRA fuel price); diesel fuel averages 98% of the cost.
4 Contribution for actual costs up to these amounts.

Table 2: GNWT Contribution to North Slave Low Water Costs: 2014-2016

1.5 SUMMARY - NORTH SLAVE HYDRO GENERATION CURRENT CAPABILITY

As explained in Attachment 2, the current North Slave hydro system appears to be drought resilient with sufficient reservoir storage[15], hydroelectric generation, and diesel resources to meet annual energy needs, and it also appears that NTPC has been reasonably managing its hydro system in a manner that minimizes the costs associated with diesel generation.

The simulation model and other information reviewed in Part 1 confirms that the North Slave's current long-term average maximized hydro generation capability of 263 GW.h/year[16] materially exceeds both current grid load requirements of about 195 GW.h/year and the assumed long-term average hydro supply availability of 220 GWh/year that was approved by the PUB[17].

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[15] The review detailed in Attachment 2 notes that this system has available storage volumes that are relatively large compared to river flows. However, there is no multi-year storage on the Snare or Bluefish systems.

[16] Long-term average annual hydro generation based on the 31-year water record from 1985 to 2015. See Table A-1, Appendix A.

[17] PUB Order for 2006/08 NTPC GRA.

The simulation in Attachment 2 shows how the long term average hydro generation capability is composed of widely varying annual hydro generation capability, depending on varying annual water availability. Accordingly, even when annual grid load is well below the long term average hydro capability, diesel generation can still be required under certain water conditions. For example, diesel generation for energy is needed in about 11% of the 31 water years (1985 to 2015) at an annual grid load of 195 GW.h, and in about 21% of the 31-year water years at the higher annual load of 255 GW.h.

Overall, the scale or level of actual annual load can limit the effective long-term average hydro generation potential that can be used to supply actual customer loads on isolated hydro systems such as the North Slave.[18] Heavily loaded systems can use their maximum potential hydro generation during flood flows and can be dispatched more efficiently than lightly loaded systems. However, when loads are lower in relation to the hydro system capability, there will be a lower effective long-term average hydro generation to supply the loads, reflecting (among other considerations) that periods of flood flows and storage constraints cannot be fully used under the lower load conditions. The North Slave system has been lightly loaded since the 2004/05 closure of the Giant and Miramar Con gold mines and can therefore be expected to have an effective long-term average hydro supply capability to supply existing loads that is below 220 GW.h/year at this time - and, as the recent drought has demonstrated, below actual grid loads approximating 195 GWh/year. In contrast, connection of a major new mining load would be expected to result in an effective long-term average hydro capability to supply loads that is above 220 GW.h/year.

In summary, actual hydro generation on the North Slave has in the past been lower than the estimated maximum capability under varying water conditions. Ignoring "must run" diesel generation required for reasons unrelated to water conditions, such hydro generation shortfalls may reflect the impacts of low loads that cannot fully utilize hydro system capability, constraints on system operation under low flows that are not adequately reflected in the current simulation model, or other factors related to actual operations.

Review of data on the North Slave grid for 2011-2015 shows that diesel demand specifically due to low water conditions can be material over a few years and can also be higher than anticipated by the maximized hydro generation simulation in Attachment 2, which reflects only the 1985-2014 water record.

- Data limited to the 2011-2014 period shows that diesel generation required due to low water for the actual North Slave load over these four years approximated 27.9 GW.h, and reflected actual hydro generation that was about 5 GW.h lower than the simulated maximum hydro output based on actual water conditions during this period.

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[18] Internal NTPC analysis has noted these observations when assessing the potential implications of transmission build out options that could lead to higher loads on the grid resulting from connection of existing diamond mines.

- Consideration of 2015 shows a negative pattern for hydro generation (adjusted for plant availability) not seen in the previous 30 years, with minimum hydro generation dropping to 125.3 GW.h/year, roughly 50 GW.h/year below the minimum that had been simulated over the previous 30 years (in 1995). Review indicates that the 2015 hydro generation reflects low reservoir levels through to June (after the very low inflows in 2014), operator focus during July through September on improving Big Spruce reservoir levels above the low supply level, and the very low inflows for the Bluefish system which persisted through 2015 well below 2014 levels.

- While there are concerns about its reliability, the available water record prior to 1985 (Figure 1) shows a long period of low flows from 1976 to 1982, as well as other earlier years with low flows in 1950 and 1951, 1962 and 1973. In short, viewed in the context of this longer period, the recent 2014-2015 drought may have been less severe overall than what would have occurred under low water flows from 1976 to 1982.

Recent experience also shows that periodic (and usually brief) other "must run" diesel requirements unrelated to water availability that are ignored in the Attachment 2 simulation assessment also impact actual diesel generation requirements for this system under all water conditions.

- From fiscal 2011/12 to 2015/16, this "must run" North Slave diesel requirement averaged approximately 7.2 GW.h/year.

- Review of available information for prior years also shows instances with large "must run" diesel generation, e.g., 2007/08 requirement for 14.4 GW.h of must run diesel (including 8.9 GW.h for Bluefish capital works, 4.6 GW.h for maintenance, and 0.9 GW.h for engine exercising and outages).

2.0 PART 2: REVIEW OF RESILIENCY OPTIONS

Part 2 reviews infrastructure and non-infrastructure options available to improve the resiliency of the North Slave system. The following are examined:

- Load Forecast Scenarios
- 2014 Charrette Report Energy Objectives
- Infrastructure Resiliency Options:
    - Default Option,
    - Hydro System Development Options,
    - Other Renewable Generation Options – Wind,
    - Other Renewable Generation Options - Solar,
    - Other Renewable Generation Options - Biomass,
    - Fossil Fuel Generation Options – LNG,
    - Other Infrastructure Resource Planning Options – Grid Expansion
    - Summary Comparison of Infrastructure Resiliency Options
- Non-infrastructure Resiliency Options:
    - Rate Related Options
    - GNWT Subsidy Options

Potential infrastructure and non-infrastructure options to improve the resiliency of the North Slave system have been examined within the following context:

- Approaches and investments that could be pursued on a horizon of the next 5 to 10 years, based on load forecast scenarios for the North Slave over the next 20 years; and
- Assessment of infrastructure options based on the 2014 Energy Charrette Report criteria and GNWT response, with "affordability" considered to be the most important objective, followed by environment, economy and energy security.

2.1 LOAD FORECAST SCENARIOS

The relatively low loads that are expected on the North Slave system materially constrain the feasibility of various resiliency options over the next 5 to 10 years. Resiliency options, including a

Default Option that assumes current hydro generation and diesel generation facilities and operation as required, are assessed against two general load scenarios:

- **Base Case forecast:** Absent new connections of major industrial (mine) loads, the Base Case forecast will likely remain similar to today's levels. In this case, existing hydro generation can supply almost all of the generation requirement in a typical year. Under this scenario, the Default Option assumes aging diesel units will be replaced as required. Other resiliency options are compared to the Default Option assuming the Base Case forecast load constraints.
- **Potential Scenarios with New Industrial Loads:** Any new grid connections to mine loads would significantly increase utilization of existing hydro generation capability as well as overall system sales. Under the Default Option, increased loads would in turn increase diesel generation requirements. A "New Mine Scenario" is therefore used to evaluate potential opportunities for new infrastructure investments to replace baseload diesel generation that is otherwise required in a typical year.

More detailed information and references are provided in Attachment 1.

2.1.1 Base Case Load Forecast

The Base Case load forecast for the next 20 years (2016-2035) as set out in Table 3 includes the following assumptions (see Attachment 1):

- Load for existing customers is expected to grow modestly at approximately 0.3% per year reflecting the actual sales trend for the last few years.
- In Yellowknife, Stanton hospital is included with a forecast incremental consumption of approximately 2.6 GW.h/year starting from 2019; and
- Giant mine freezing load is included with approximately 13.4 GW.h/year incremental consumption starting from 2020.

A number of operating and potential mine activities in the North Slave region currently supply (or would supply, if developed) their own power using diesel. High level discussions have been held with some mines regarding potential connections to the North Slave grid, but no specific commitments have yet been made. The Base Case load forecast therefore assumes no new industrial loads.

In summary, the Base Case forecasts total generation to remain at approximately 194-200 GW.h/year through 2019 before increasing to approximately 215 GW.h in 2020 due to the addition of the Giant mine freezing load. After 2020, load on the North Slave system is forecast to grow conservatively and reach 224 GW.h/year by 2035. Absent any new industrial connections or special new initiatives to increase electricity use (e.g., for electric vehicles), the long-term North Slave system Base Case load is forecast to continue being significantly below pre-2005/06 levels.

	Baseload w/o Mine Connections		
Fiscal Year	Sales	Losses/SS	Generation
2016	182.1	11.3	193.5
2017	182.6	13.6	196.3
2018	183.1	14.2	197.3
2019	186.3	14.3	200.6
2020	200.2	15.2	215.3
2021	200.7	15.3	216.0
2022	201.2	15.3	216.5
2023	201.8	15.4	217.1
2024	202.3	15.4	217.7
2025	202.9	15.4	218.3
2026	203.4	15.5	218.9
2027	203.9	15.5	219.5
2028	204.5	15.6	220.1
2029	205.0	15.6	220.6
2030	205.6	15.6	221.2
2031	206.1	15.7	221.8
2032	206.7	15.7	222.4
2033	207.2	15.8	223.0
2034	207.8	15.8	223.6
2035	208.4	15.9	224.2

Table 3: Base Case Load Forecast for North Slave System: 2016-2035

2.1.2 Potential Scenarios with Industrial Loads

Existing and potential new industrial loads in GNWT rely on mine site diesel generation unless transmission connection can be arranged to the hydro grids. Based on discussions with GNWT, Table 4 summarizes eight potential industrial load connections to the North Slave hydro system in the next 10 years. Each potential mine load requires new transmission infrastructure.

The first four of these potential new grid loads shown in Table 4 are existing diamond mines located to the east of the North Slave system, where connection of one mine (e.g., Snap Lake) might provide the basis to connect some or all of the remaining diamond mines. However, De Beers Canada announced on December 4, 2015 that the Snap Lake mine will be placed on care and maintenance and all mining stopped in light of current market conditions.

The remaining four potential industrial loads in Table 4 pertain to mines that are not currently established, and these potential loads are therefore subject to the added uncertainties associated with new mine development.

Mine Name	Annual Energy (GW.h/yr)	Potential Connection	Currently Operating?	Termination	Distance to Grid (km)
Snap Lake	80.0	2020	No	2031	225
Diavik Mine	170.0	2020	Yes	2024	415
Ekati Mine	122.2	2020	Yes	2031	378
Gahcho Kue Mine	60.0	2020	Yes	2030	270
Avalon Rare Earth	85.0	2020	No	2034	95
Nico Mine	84.0	2020	No	2035	30
Tyhee Gold Mine	65.0	2020	No	2025	60
Seabridge Mine	354.8	2021	No	2036	90

Table 4: Potential New Mine Connections to North Slave System: 2016-2025

Load forecast scenarios are sensitive to a range of potential new mine connections, most of which increase annual grid load by over 80 GW.h/year. Connection scenarios for the four existing diamond mines are sensitive to near-term policy assessments as to the value of such an initiative. Connection scenarios for the remaining four potential new mines within 95 km of the existing grid depend on the development timing for each new mine.

2.1.3 Summary of Load Forecast Scenarios

Figure 9 shows the Base Case load forecast generation load from 2016 to 20135. It also illustrates a scenario with the Base Case load forecast plus assuming all potential new mines listed in Table 4 are connected. The four existing diamond mines are shown as one set of potential opportunities - with Snap Lake the closest (225 km) but not currently operating, followed by the new mine being constructed (Gahcho Kue at 270 km). The remaining four other new mines identified for possible development are all within 95 km of the grid -Figure 9 shows Seabridge separately, as it is by far the largest.

Figure 9 also shows the "New Mine" scenario with the Base Case load forecast plus one new mine that requires 80 GW.h/year of generation from 2020 to 2035. Resiliency options are assessed for the Base Case and the New Mine scenario.

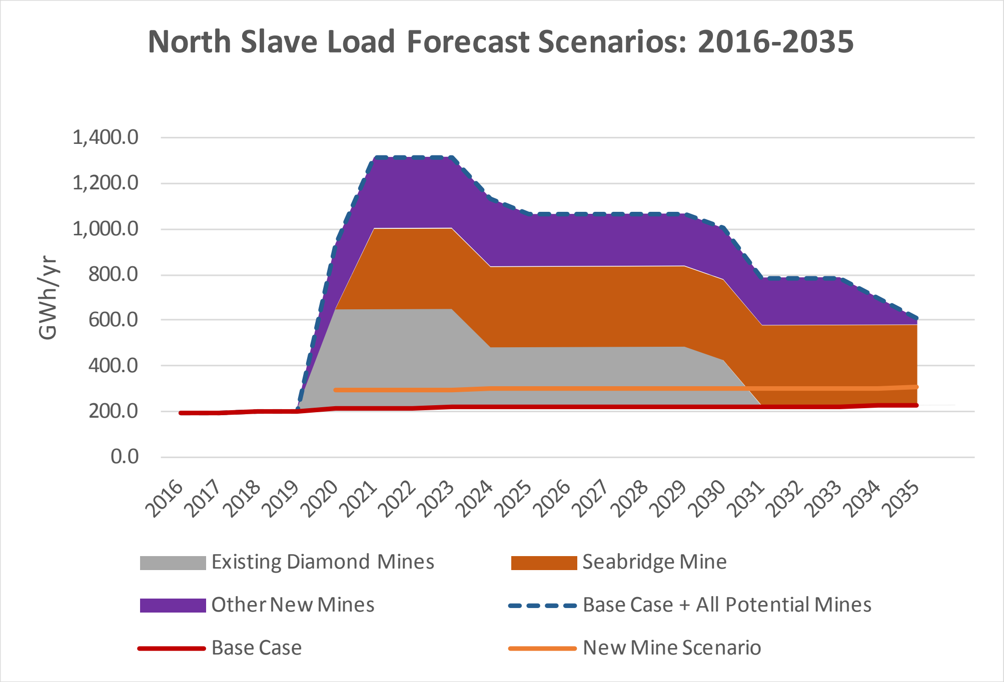

Figure 9: North Slave Load Forecast Scenarios: 2016-2036

2.2 2014 CHARRETTE REPORT ENERGY OBJECTIVES

The 2014 Charrette Report and GNWT response identified "affordability" as the prime energy objective, highlighting the importance of options that minimize overall costs for GNWT subsidies and community electricity ratepayers (see Attachment 1). They also identified three other criteria to be considered when evaluating energy options:

- Environment (minimize GHG emissions and environmental footprint);
- Economy (local NWT economy benefits); and
- Energy security (improve system reliability and reduce community vulnerability to future price escalations).

The Study uses these criteria to compare infrastructure option costs and assess affordability impacts. This assessment considers likely diesel fuel and new bulk power capital costs to meet the Base Case load forecast scenario and potential new mine connection scenarios.

2.3 INFRASTRUCTURE RESILIENCY OPTIONS

2.3.1 Default Infrastructure Option

The default infrastructure option (Default Option) assumes the current hydro generation capability and adjustments to diesel generation capability as required to meet both energy and capacity planning requirements for any load scenario.

The incremental diesel generation fuel and O&M costs required for the Default Option are used as the basis for assessing the affordability of other infrastructure options - and, as reviewed below, the Default Option's use of diesel tends to rank very high on affordability under the forecast load conditions. On energy security, diesel ranks high on reliable capacity and supply, which (along with its flexibility to accommodate capacity and energy changes) accounts for its use on this isolated hydro grid; however, diesel displays high vulnerability to future price changes (both reductions and escalations). On other criteria, diesel ranks poorly on environment (high GHG and other emissions) and economy (low NWT economy benefits).

<u>Base Case Load Scenario</u>: Long-term average (LTA) annual maximized hydro generation capability under the Default Option for the existing North Slave system exceeds grid loads under the Base Case forecast load scenario for the next 20 years (see Table 3). Therefore the forecast demand for diesel generation for energy loads under the Base Case scenario comes from sporadic winter peaking, maintenance and overhaul, emergency and other outages, and from months or years of continued operation under low water conditions.

Diesel generation requirements for the Default Option are therefore addressed by a range of potential average annual diesel generation over the next 20 years. The ranges address uncertainty involved in estimated future load conditions within any given scenario. The hydro utility industry commonly uses the "averaging" approach in order to address LTA hydro and diesel generation requirements and costs for any given load scenario or resiliency option when the timing of future flow conditions (including extreme low water levels) cannot be known in advance.[19] The prior Part 1 analysis of actual diesel generation (including 2015) is used to assume the following Default Option diesel requirements:

- Average 2 to 4 GW.h/year for "must run" diesel for reasons such as peaking, mandatory engine exercise and specific outages where only diesel can be used to retain power as well as overhaul or other planned interruptions where diesel is currently selected as the only available dispatchable option; and

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[19] If material load growth is assumed over the planning period without any change in real thermal fuel costs per kW.h, the "averaging" approach will understate future nominal value thermal generation costs if drought conditions occur near the end of the forecast period (and vice versa if such drought conditions occur only near the start of the forecast period).

- Average 3 to 6.5 GW.h/year for low water-related diesel reflecting potential LTA diesel at 2016 [194 GW.h] and 2035 [224 GW.h] Base Case load. [Figures A-2 and A-3 in Appendix A illustrate for each water or flow year the Default Option impacts on diesel generation requirements, hydro generation utilization, and hydro spill at each of these loads.]

This leads to diesel generation ranging from an average of 5 to 10.5 GW.h/year, with a fuel and other O&M cost of $0.256/kW.h (2015$)[20]. Diesel fuel price accounts for 94% of this cost. Uncertainty as to future oil and diesel prices is a key risk factor affecting affordability assessments of resiliency infrastructure options.

In addition to diesel energy generation requirements, new firm capacity will be needed under the Base Case forecast load scenario to replace the second Mirrlees (5.2 MW) and to meet future load growth (the first Mirrlees is already being replaced, as noted later). An additional 5 modular units (1.15 MW per unit) are therefore assumed over the next few years at a cost of $6.2 million (2015$). This assumed requirement may be reduced if Bluefish replacements and upgrades required in the next 10 to 15 years add firm capacity. However, it may be increased by various factors, including grid load growth and/or accelerated retirements of other existing diesel units due to long running hours required during the recent drought and hydro unit overhauls (see Attachment 1, Section 1.2.6 and Table A1-2).

Assuming NTPC cost of new capital (debt and equity) at 6.0%/year[21], the present value incremental cost (2015$) for diesel generation fuel and O&M as well as new capacity requirements over 20 years for the Default Option is approximately $24 to $43 million[22]. Other resiliency options will be assessed against this value to determine if lower costs can be secured to meet forecast load requirements.

<u>Load Scenario with New Mine Connections</u>: Absent transmission connection to the North Slave grid, existing diamond mines rely primarily on diesel generation and new mines would also rely on fossil fuel (diesel or LNG) generation. There is a wide range of potential load scenarios with new mine

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[20] Assumes diesel fuel costs at $0.24/kW.h (at average efficiency of 3.65 kW.h/litre [current approved average for this system], the assumed fuel price is about $0.88 per litre - reflects actual NTPC fuel price for this grid in June 2015, versus lower average cost of about $0.71 per litre for the balance of 2015) plus allowance for non-fuel O&M at about $0.016/kW.h. The fuel cost is sensitive to ongoing uncertainty in the price of oil, exchange rates, and the market price for diesel fuel. Somewhat lower costs will occur if new engines provide higher efficiency, e.g., at 4.28 kW.h/litre the equivalent average fuel cost would be $0.206/kW.h.

[21] It is assumed that new long term debt (LTD) is available for new capital at slightly over 4.0%, that return on equity is at 8.5%, and that the equity to debt ratio is 43/57. NTPC's approved cost of capital at the last GRA was 6.88%/year (8.5% ROE and 5.68% LTD with 43/57 equity to debt ratio).

[22] Assumes fuel and non-fuel O&M ($0.256/kW.h) escalate at 2%/year (or "real" cost of capital net of inflation is about 3.92%/year). Includes capital cost at $6.2 million for 5.75 MW of new modular diesel unit capacity. Assumes LTA diesel generation each year for 20 years as required for the assumed load range, i.e., no attempt to predict timing of actual diesel generation variances due to varying water conditions.

connections to this grid. Ignoring transmission connection costs, each possible scenario would materially increase the LTA diesel fuel and O&M requirements assumed in the Default Option. Depending on NTPC's arrangements with the new mine, each scenario may also increase the firm capacity cost requirements relative to the Base Case.

The New Mine scenario assumes a 295 GW.h/year load on the grid in 2020, resulting from connecting one new mine at that time with requirements of 80 GW.h/year of new grid generation through to 2035. Based on the earlier assessments, LTA diesel requirements in 2020 at such a grid load would approximate 32 GW.h/year[23] plus an additional 2 to 4 GW.h/year must-run diesel generation that are unrelated to water conditions. The present value cost through to 2035 of the incremental diesel fuel and other O&M from 25.3 to 28.8 GW.h/year added diesel generation resulting from connecting such a new mine in 2020 (with an added 80 GW.h/year of grid generation each year to 2035) approximates $53 to $62 million (2015$).[24]

2.3.2 Hydro System Development Infrastructure Options

NTPC's Longer Term Resource Planning and Drought Management document for the North Slave system, dated March 30, 2015, identified hydro system development options for the Snare and Bluefish systems, as well as at Lac La Martre (see Attachment 3):

- Additional storage can potentially be developed on the Snare hydro system, including an estimated 175 million m^3 (providing about 30 GW.h at the existing hydro plants) potential live storage at Ghost Lake assuming a lake level range of 4 metres. Additional planning studies to examine specific design implementation options, social and environmental impacts, licensing requirements, estimated costs and potential benefits are required to assess this option. Because the Snare and Bluefish systems each have relatively large existing live storage capability relative to flows,[25] any additional storage would need to have minimal development costs and be specifically designated for use solely to reduce the impact on the existing hydro facilities of severe low water conditions. If used during a single drought, 30 GW.h of added storage would save diesel costs of about $7.7 million at fuel and

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[23] This high level estimate is based on the gap between the assumed 295 GW.h annual generation load and the simulated maximum hydro generation as reviewed in Table A-1 for each of the 30 years (1985-2014) assessed in the Attachment 2 simulation plus the 2015 hydro capability estimate (125.3 GW.h). Over the 31 years reviewed, the total diesel generation requirement to fill the various annual gaps is estimated at 984.5 GW.h, i.e., the LTA diesel per year over the 31 years then equals 31.8 GW.h/year. See Table 5.

[24] Assumes NTPC cost of capital at 6.0%/year, diesel fuel cost after mine connects at $0.206 (assumes new engines at 4.28 kW.h/litre and fuel cost at about $0.88/litre [2015$]), non-fuel O&M at $0.016/kW.h (2015$), and 2.0%/year escalation of these fuel and non-fuel O&M costs. Assumes Base Case costs for period before mine connects.

[25] Big Spruce Lake on the Snare system has live storage of approximately 546 million m^3 and Duncan Lake on the Bluefish system operates as a seasonal reservoir with a live storage capacity of approximately 207 million m^3.

O&M costs of $0.256/kW.h. Further future examinations are needed to confirm the feasibility of any specific improvement option.

- The Bluefish hydro station's initial unit and related facilities are nearing end of life and will need replacement or rehabilitation within 10 to 15 years. A study is planned to start in 2016 to explore options, including the potential for increasing storage and/or plant peaking capacity (which would require added capital costs beyond the simple replacement of the initial unit, without addressing any drought-related resiliency issues). An approved plan to upgrade Bluefish will likely be required within the next five years. The current evaluation assumes that Bluefish will continue to be available throughout the planning forecast period at current capacity and energy operation levels.
- Planning studies have indicated up to 13 MW of potential hydro-electric development at Lac La Martre, and many options for potential expansion of the Snare hydro system, which could provide up to 20 MW of additional hydro capacity.

Given the very preliminary information available on these options, the time normally needed to plan and develop new or rehabilitated hydro facilities, and the Base Case load forecast scenario (which indicates no basis for developing new hydro capacity at this time), these options are not considered candidates today for near term action and/or further examination to address drought resiliency issues. It is noted, however, that Bluefish upgrade within the next 10 to 15 years may affect consideration of other new renewable options in the near term.

2.3.3 Other Renewable Generation Infrastructure Options - Wind

NTPC and the GNWT are investigating non-hydro renewable generation options such as biomass generation, wind farms, solar, and battery energy storage systems. NTPC in December 2015 issued an Expression of Interest for between 1 to 10 MW of new wind or solar projects for the North Slave system.

This resiliency Study has focused its examination of other renewable options to the potential for new wind generation to improve North Slave resiliency. Wind generation ranks high on environment (minimal GHG emissions) and reducing vulnerability to future price escalations, medium on economy (local NWT benefits), and low on system reliability and energy security. Affordability is the key issue for all options, as well as current information on local supply capabilities in the near term. Absent wind being an affordable option relative to Default Option diesel, available information indicates that there is no current basis to consider any of the other renewable infrastructure options to improve resiliency in the near-term period.

Even in the case of the wind option, considerable further wind monitoring and planning would be needed before any specific option could be defined for a meaningful feasibility assessment of possible near-term development.

Based on preliminary investigations done in 2008 and 2015 by the Aurora Research Institute (see Attachment 3), a 20 MW wind farm option is examined for the purpose of this screening assessment with the following assumptions:

- Options are assumed to exist for wind farm developments of approximately 20 MW with large wind units (1.5 MW), an annual capacity factor of 20 to 25% harvested wind energy, a capital cost of $3.5 million per MW (2015$), annual O&M costs of $0.1 million per MW (2015$), and an economic life of 20 years. These assumptions ignore any added capital costs related to system stability requirements and/or connection of specific sites to the grid, which would need to be estimated and added to the cost estimates for any feasibility assessment.
- Based on these assumptions, a 20 MW wind farm would have a capital cost of $70 million plus a present value O&M cost of approximately $27 million (2015$).[26] The level of average annual generation available for the grid would range between 35 and 44 GW.h/year (20% to 25% capacity factor). For this study, the higher estimate of 25% or 44 GW.h/year has been assumed.

Economic benefits for the assumed 20 MW wind farm option are estimated for the Base Case and New Mine load scenarios based on the potential present value savings of LTA diesel generation costs (excludes "must run" diesel generation costs)[27] as estimated for the Default Option. Savings of LTA diesel generation (GW.h/year) are estimated for each assumed grid load scenario assuming 44 GW.h/year of wind farm generation and the 31 water years of hydro generation. Default Option diesel generation varies widely in any year depending on the assumed water conditions, and therefore the ability of the wind farm generation to displace Default Option diesel generation at any assumed grid load also varies in any year depending on the assumed water conditions (see Table 5). The estimated diesel generation displacement by wind for each water year is based only on maximized annual hydro generation for the 31 water years as shown in Table 5, and therefore likely overstates wind displacement of diesel.[28] A feasibility assessment for wind would therefore need model capability to assess diesel displacement within each year.

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[26] For consistency, the present value O&M cost assumes a real discount rate of 3.92% (assumes annual O&M cost escalates at 2% per year and 6.0% nominal cost of capital per NTPC). Actual cost of capital would likely be higher if another party developed the wind farm in order to sell the energy to the grid.

[27] No attempt is made to assess what portion of the assumed "must run" diesel range of 2 to 4 GW.h/year might be eligible for displacement by wind generation. Although some of this diesel likely could be displaced by wind generation, a material portion will continue to be required for unit exercising, system peaking requirements, and some of the system outages. Conversely, as noted separately, the Table 5 diesel displacement estimates for wind likely overstate the ability of wind generation to displace Default Option LTA diesel generation - and in this context it is assumed reasonable to exclude any of the "must run" assumed diesel from the current assessment.

[28] Due to current hydro generation model limitations, the annual Default Option diesel generation estimates ignore the extent to which Default Option diesel generation is expected to vary materially within each year

Preliminary economic assessments of the wind farm option are provided for each load scenario based on the above assumptions (see also Figures A-4 and A-5 in Appendix A which illustrate for each water or flow year the Wind Option impacts on diesel generation requirements, hydro generation utilization, and hydro spill at each of the grid loads reviewed below):

- Base Case load scenario: The Default Option LTA diesel generation requirements under the Base Case load forecast scenario are estimated at 3 to 6.5 GW.h/year. The wind option would reduce the need for this diesel generation fuel and other O&M costs, estimated (with "must run" diesel included) at approximately $18 to $37 million present value over 20 years (2015$) under the Base Case load forecast scenario. However, even if all this diesel was displaced, the potential benefits from savings in diesel costs would be well below the wind farm present value costs of $97 million (2015$).

  As reviewed in Table 5, the 20 MW wind farm will not be able to displace all of the assumed diesel generation requirements related to severe drought situations. The assumed wind generation capability at 44 GW.h/year (fully utilized) would be less than the 69 GW.h/year diesel generation needed for 2015 water conditions with even the 194 GW.h Base Case load. On a LTA basis, the wind farm's 44 GW.h generation would on average displace about 2 to 5 GW.h per year of diesel generation over the 20 years with present value benefits (2015$) of $8 to $16 million to 2035. Wind displacement of Default Option diesel with Base Case loads occurs in only 3 to 4 of the 31 water years (see Figures 10 and 11).

(both due to water variability and load variability within the year). Wind generation may also vary to some extent by season. It is likely, however, that a more refined week-by-week model assessment for each water year would reveal additional situations within years with higher diesel generation requirements where wind ability to displace diesel is capped by the assumed wind generation level. As a result, overall LTA diesel displacement by wind generation is likely overestimated in the Table 5 assessment.

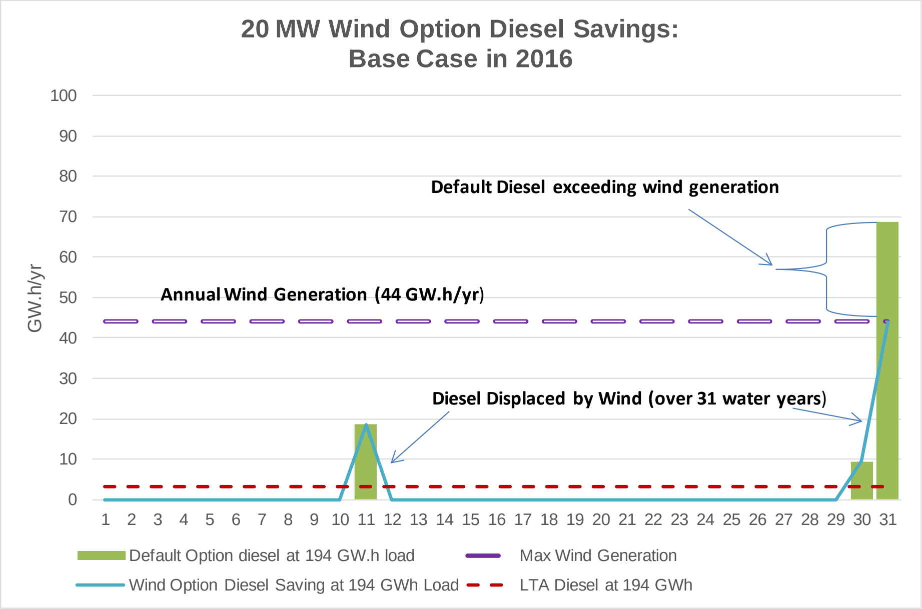


Figure 10: 20 MW Wind Option Impacts by Water Year: Base Case Load in 2016 at 194 GW.h/year

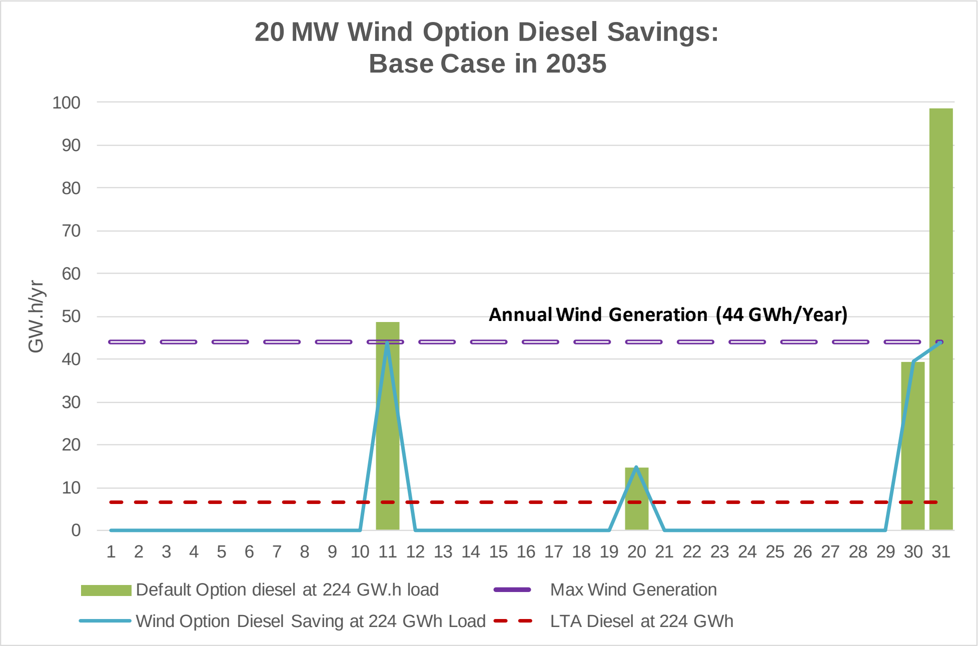


Figure 11: 20 MW Wind Option Impacts by Water Year: Base Case Load in 2035 at 224 GW.h/year

- Load Scenario with New Mine Connections: Under a load scenario with connection of an 80 GW.h/year new mining load in 2020, incremental diesel generation was estimated to average 25 to 29 GW.h/year with added fuel and other O&M costs estimated at approximately $53 to $62 million present value to 2035 (2015$). Total Default Option present value fuel and other O&M costs for this scenario were estimated at about $80 to $90 million to 2035 (2015$).

  These estimated diesel generation costs reflect varying hydro generation depending on water availability such that wind benefits will be minimized in years of high water availability and will be inadequate to displace all diesel requirements in years of low water availability or specific must-run diesel situations. Accordingly, wind will not displace all of the present value diesel fuel and other O&M diesel generation costs - but the extent of this shortfall can only be reliably estimated through detailed further studies.

  Table 5 provides a preliminary assessment assuming 44 GW.h/year of wind generation which indicates that average annual Default Option LTA diesel displacement with 20 MW of wind would at most approximate 21.6 GW.h/year, i.e., 49% of the 44 GW.h/year of assumed wind generation would be used to displace LTA diesel generation with a grid load of 295 GW.h/year. Wind is fully used to displace diesel in 5 of the 31 water year (see Figure 12).

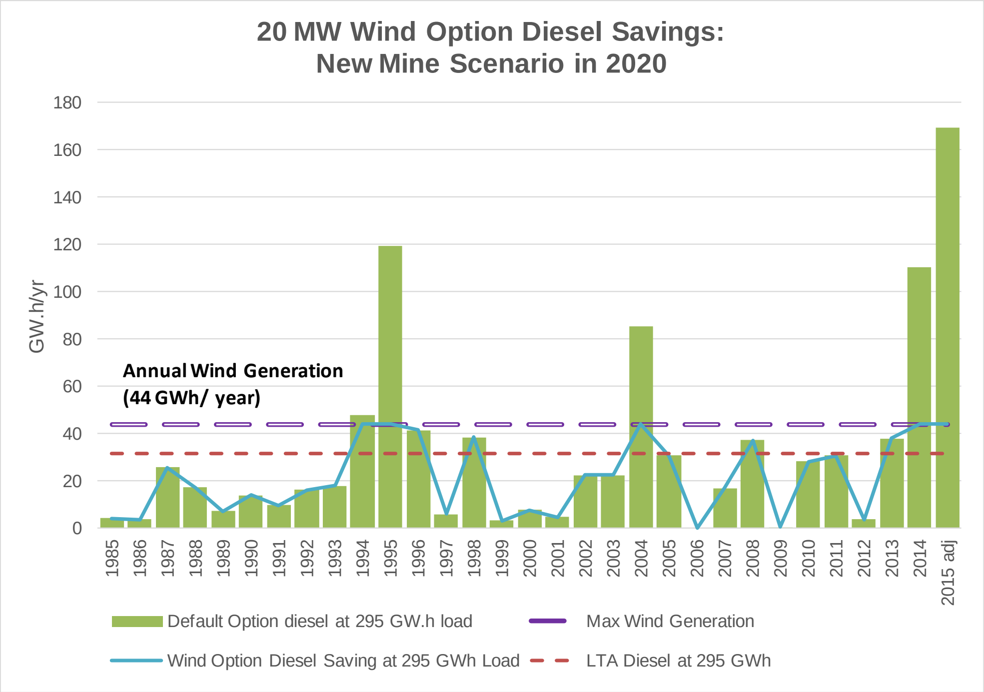
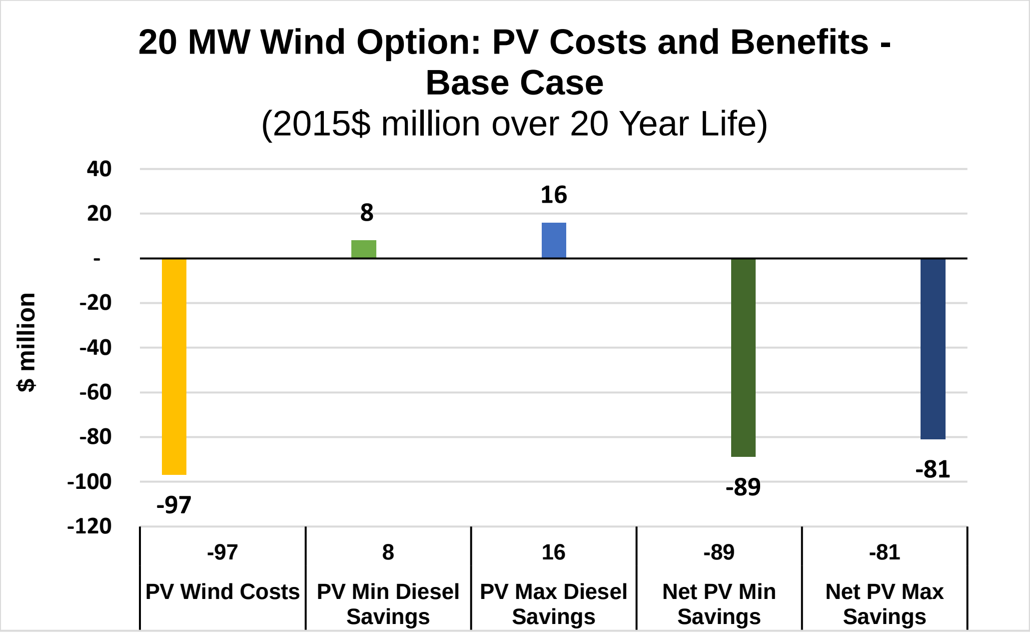


Figure 12: 20 MW Wind Option Impacts by Water Year: New Mine Scenario in 2020 at 295 GW.h/year

For assessing potential maximum diesel displacement benefits from the 20 MW wind farm, a range of +/-10% was assumed around the 21.6 GW.h/year LTA as estimated in Table 5.[29] Maximum potential present value benefits (2015$) under these assumptions approximate $43 to $53 million to 2035 – and therefore the diesel cost savings would not equal the wind option's present value costs of $97 million (2015$). In general terms, the assessed benefits would be lower at lower grid loads, and higher at higher grid loads.

- Impact on grid capacity requirements: The new wind farm capacity would not provide reliable firm capacity, and therefore would not provide any capacity cost savings relative to the Default Option.

In summary, the 20 MW wind farm renewable generation infrastructure option would increase consumer costs compared to the Default Option (diesel generation). As reviewed in Figure 13 and 14 below, the gap between wind option costs versus maximum potential diesel cost saving benefits is very large at Base Case load forecasts; however, a material gap remains even with the New Mine load scenario. It is re-iterated that the above analysis is very preliminary, both with regard to assessment of likely wind project capital cost requirements as well as with regard to the likely diesel displacement benefits.



PV Wind Costs	PV Min Diesel Savings	PV Max Diesel Savings	Net PV Min Savings	Net PV Max Savings
-97	8	16	-89	-81

Figure 13: Summary PV Costs and Benefits for Wind Infrastructure Resiliency Option (Base Case Scenario)

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[29] This range reflects consideration of the Table 5 LTA diesel displacement estimate being overstated (due to inability to consider weekly generation within the water year) as well as the underestimate of wind benefits due to the assumption that no "must run" diesel is being displaced.

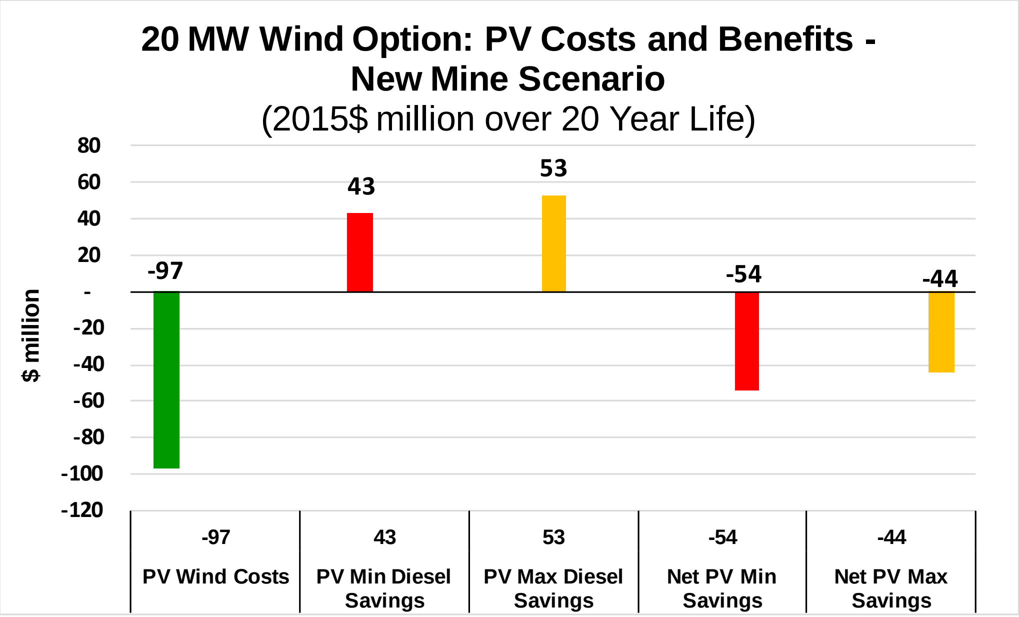

Figure 14: Summary PV Costs and Benefits for Wind Infrastructure Resiliency Option (New Mine Scenario)

Reducing the scale of wind development to well under 20 MW cannot be assumed to resolve the above assessment, even with the higher load forecast scenario assuming connection of a major new mine. For example, Default Option diesel savings for the New Mine load scenario (295 GW.h/year in 2020) with a 10 MW wind farm is estimated at 15 GW.h/year, i.e., 69% of the benefits estimated with a 20 MW wind farm. Even if wind PV costs per MW remained unchanged (rather than increase as expected for a smaller scale project), wind PV costs at $43.5 would still exceed maximum potential PV benefits at $33 million even with the New Mine load scenario.

Even with full utilization of all wind generation to displace diesel energy generation, a wind capacity factor of 20% results in an energy cost of $0.20/kW.h (2015$) at an average capital cost of $3.5/MW and real discount rate of 3.9%/year. Smaller scale wind developments to move toward higher effective wind utilization, however, are likely to face higher average capital costs per MW that need to be assessed before any useful evaluation can be made of such options.

Overall, wind (unlike existing hydro) is an example of a capital intensive renewable resource infrastructure option that does not provide reliable capacity, and therefore does not displace the need for Default Option new diesel generation capacity. At $0.20/kW.h cost when fully utilized (as estimated above assuming capital costs that are likely too low), wind's cost would equal 78% of the average fuel and O&M cost for existing diesel generation and 97% of these costs for new diesel units (assuming diesel fuel prices adopted for this study versus the lower actual costs observed in the last half of 2015) – without offering any of the flexibility provided by diesel generation to cut these costs when and if load requirements are reduced. Assuming continuance of the isolated grid, these factors underline the need for reliable, stable, long-term grid loads involving major new mine connections as the foundation for consideration today of major new capital intensive renewable resource options for the North Slave.

Wind Option Diesel Savings (GW.h/year) over 31 water years with varying Grid Load with Wind Option @ 44 GW.h/year

Water Year	Simulated Maximum Hydro	194 GW.h load Default Option LTA diesel (ex. "must run" diesel)	194 GW.h load Wind Option Diesel saving	224 GW.h load Default Option LTA diesel (ex. "must run" diesel)	224 GW.h load Wind Option Diesel saving	295 GW.h load Default Option LTA diesel (ex. "must run" diesel)	295 GW.h load Wind Option Diesel saving
	(GW.h/year)	(GW.h/year)	(GW.h/year)	(GW.h/year)	(GW.h/year)	(GW.h/year)	(GW.h/year)
1985	290.7	0.00	0.0	0.00	0.0	4.32	4.3
1986	291.2	0.00	0.0	0.00	0.0	3.79	3.8
1987	269.1	0.00	0.0	0.00	0.0	25.95	25.9
1988	277.7	0.00	0.0	0.00	0.0	17.27	17.3
1989	287.8	0.00	0.0	0.00	0.0	7.23	7.2
1990	280.9	0.00	0.0	0.00	0.0	14.11	14.1
1991	285.3	0.00	0.0	0.00	0.0	9.71	9.7
1992	278.6	0.00	0.0	0.00	0.0	16.42	16.4
1993	276.8	0.00	0.0	0.00	0.0	18.17	18.2
1994	247.0	0.00	0.0	0.00	0.0	47.99	44.0
1995	175.4	18.57	18.6	48.57	44.0	119.57	44.0
1996	253.4	0.00	0.0	0.00	0.0	41.57	41.6
1997	288.8	0.00	0.0	0.00	0.0	6.18	6.2
1998	256.5	0.00	0.0	0.00	0.0	38.50	38.5
1999	291.7	0.00	0.0	0.00	0.0	3.29	3.3
2000	287.2	0.00	0.0	0.00	0.0	7.75	7.8
2001	290.3	0.00	0.0	0.00	0.0	4.71	4.7
2002	272.3	0.00	0.0	0.00	0.0	22.70	22.7
2003	272.5	0.00	0.0	0.00	0.0	22.52	22.5
2004	209.3	0.00	0.0	14.71	14.7	85.71	44.0
2005	264.2	0.00	0.0	0.00	0.0	30.78	30.8
2006	296.2	0.00	0.0	0.00	0.0	0.00	0.0
2007	277.8	0.00	0.0	0.00	0.0	17.18	17.2
2008	257.7	0.00	0.0	0.00	0.0	37.28	37.3
2009	294.4	0.00	0.0	0.00	0.0	0.57	0.6
2010	266.8	0.00	0.0	0.00	0.0	28.22	28.2
2011	264.1	0.00	0.0	0.00	0.0	30.87	30.9
2012	291.1	0.00	0.0	0.00	0.0	3.87	3.9
2013	256.8	0.00	0.0	0.00	0.0	38.18	38.2
2014	184.6	9.41	9.4	39.41	39.4	110.41	44.0
2015 adj	125.3	68.67	44.0	98.67	44.0	169.67	44.0
31-yr. av.	**263.3**	**3.1**	**2.3**	**6.5**	**4.6**	**31.8**	**21.6**
Share of LTA Diesel Displaced			**74%**		**71%**		**68%**
Use of Wind Generation @ 44 GW.h/yr			**5%**		**10%**		**49%**

Table 5: Wind Option Diesel Savings over 31 water years with Base Case and New Mine Scenarios

2.3.4 Other Renewable Generation Infrastructure Options – Solar

With respect to the North Slave system, there are very few solar generation installations currently in place. As of July 2013, the installed solar generation capacity was approximately 5 kW in Yellowknife and 9.8 kW in Behchoko.[30] However, NTPC has also recently announced an Expression of Interest call for new solar project ideas in the North Slave region.

Solar is a capital intensive renewable option, similar to wind, that is not dispatchable and does not contribute to required firm or reliable capacity on the North Slave system. NTPC's March 30, 2015 Resource Planning and Drought Management document also notes that a large scale solar application would have a substantial footprint, and that this option is likely better suited for smaller applications implemented by individual customers under NTPC's existing net metering policy.

In contrast to the wind option, information available for this Study was very limited as regards specific solar option costs, generation capability, or sites specific to the North Slave. Accordingly, analysis has focused on what if any benefits might be provided by any solar generation that is made available (without attempting to address the potential capital and operating costs required for this option or its forecast ability to provide energy throughout the year).

As shown above in Section 2.3.3 for the wind option, under Base Case loads new solar generation will only provide notable reduced diesel generation costs for NTPC customers in very occasional years when there is a drought. Under most conditions under currently forecast loads, new solar generation when it is available will therefore only result in increased spill of existing hydro generation capability.

Overall, solar generation ranks high on environment (minimal GHG emissions) and reducing vulnerability to future price escalations, medium on economy (local NWT benefits), and low on system reliability and energy security. Affordability is the key issue for all options, as well as current information on local supply capabilities in the near term. As noted earlier, absent wind being an affordable option relative to Default Option diesel, available information indicates that there is no current basis to consider any of the other renewable infrastructure options to improve resiliency in the near-term period.

Assuming continuance of the isolated grid, consideration of all relevant factors underlines the need for reliable, stable, long-term grid loads involving major new mine connections as the foundation for consideration today of any major new capital intensive renewable resource options for the North Slave.

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[30] See Northland Utilities Net Metering Program application, dated July 31, 2013; NTPC response to the PUB Board Order 1-2014, dated April 1, 2014.

2.3.5 Other Renewable Generation Infrastructure Options – Biomass

NTPC's March 30, 2015 Resource Planning and Drought Management document notes that a 10 MW biomass plant could be constructed in or near Yellowknife, which would provide firm capacity to the North Slave system, helping to improve the resiliency of the system.

The NTPC March 30, 2015 report noted that key factors affecting the economic viability of the biomass option include finding customers for the heat produced by the system to offset the capital costs and securing a long-term fuel supply. Without a secure fuel supply and the ability to generate some revenue from heat sales, NTPC note that this option would likely be more expensive than diesel generation for stand-by service.

Unlike wind and solar options, biomass thermal renewable options are dispatchable and can provide reliable capacity. However, cost effective use of such facilities typically requires reasonably high utilization (e.g., above 70% on an annual basis) to supply base or stable grid loads. Consideration of combined biomass thermal generation with district or other heating uses of the waste heat typically (in order to help reduce capital costs for NTPC customers) also requires reliable and stable grid loads to ensure that the heating related uses are reliable and economic.

On the isolated North Slave hydro grid, biomass generation options would only provide benefit for NTPC customers to the extent that the generation was able to displace reliance on diesel generation. Figures 10, 11 and 12 demonstrate the severe limitations in that regard with the assumed North Slave Base Case and even with New Mine Scenario grid loads.

In short, sustained reasonably high annual utilization of a biomass generation option on the North Slave system does not appear to be an economic option for consideration at any time in the near future.

2.3.6 Fossil Fuel Generation Infrastructure Options - LNG

NTPC's Longer Term Resource Planning and Drought Management document of March 2015 noted that a 10 MW natural gas plant could be constructed in or near Yellowknife to provide firm capacity to the North Slave system, with savings in fuel costs and reductions in GHG emissions compared with diesel fuel. This fossil fuel option would require storage for liquefied natural gas (LNG) that is likely to be supplied by highway transport from Alberta or British Columbia. It was noted by NTPC that LNG has proved to be a reliable option as part of the generation mix in Inuvik. It was also noted by NTPC that LNG storage costs and storage life may provide challenges when this fuel is used primarily for stand-by. NTPC's report noted that factors which would help secure an LNG supply chain and possibly reduce unit storage costs include use of dual fuel units (that can use LNG or diesel or another type of fuel), LNG supply for municipal gas distribution, industrial customer use, or heating applications.

LNG can offer 25% or more GHG emission reductions compared to diesel fuel, similar supply security (reliability) benefits to diesel fuel (with likely improvement to fuel price security), and similar economy impacts. In assessing LNG environmental impacts, it is relevant to maintain the comparison with diesel generation as the option that would otherwise be selected to provide reliable backup generation for loads that cannot otherwise be cost effectively supplied by new capital intensive renewable generation. In this context, LNG provides clear GHG reductions that would otherwise not be achieved.

As reviewed below, LNG affordability impacts are very much affected by expected usage levels - but cost savings relative to diesel are expected at relatively low levels of expected use.

- LNG involves higher capital costs than diesel for NTPC to accommodate LNG storage and vaporization of the LNG back to natural gas. It also is expected to provide lower operating costs than for equivalent diesel generation. Overall, the LNG option therefore requires expected LTA operation that is at least adequate to accrue fuel cost savings that will offset the added capital costs - and this can occur at relatively low capacity utilization.[31]

- Excluding storage and vaporization costs, a key factor affecting affordability is that the natural gas option provides reliable and flexible dispatchable generation that tends to involve capital costs per MW and non-fuel O&M costs per kW.h of generation similar to diesel fuel generation. Adoption of the LNG option therefore tends to be attractive when new fossil fuel generation is otherwise required for firm capacity requirements, e.g., due to retirement of existing diesel units and/or a need for new capacity to serve new load. LNG can also be an option for blended natural gas and diesel fuel operation of retrofitted existing diesel units.

- NTPC's March 2015 report noted the specific issue of storage life with LNG, and the challenges that may occur when this fuel is used primarily for stand-by. Under load scenarios where on-site stored LNG may not be used for thermal generation for months or years, it is necessary to provide for alternative uses for boil off gas related to the stored LNG. Aside from LNG use for routine engine exercising, other potential uses (e.g., local heating applications) merit consideration.[32]

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[31] Affordable LNG compared to diesel can occur at relatively low capacity utilization for new natural gas facilities. For example, assuming 25% fuel cost savings for a new unit ($0.055/kW.h saving assumed in this study), a $10 million added capital cost for LNG storage, vaporization and other LNG-specific facility costs would be offset over 20 years by average annual natural gas generation of about 13.3 GW.h/year or about 15% average use of 10 MW new natural gas generation capacity. [PV cost saving estimated assuming NTPC real average cost of capital at 3.926%/year net of inflation.]

[32] Yukon Energy's recent replacement of end-of-life Mirrlees with LNG units took place on a hydro grid where water-related diesel generation requirements are still periodic due to overall grid load levels. The issue of LNG boil off gas use was addressed in this context.

Based on available information, the following additional factors related to the North Slave are noted regarding the LNG option for this screening assessment:

- Site issues require further study to be resolved prior to any LNG development in the Yellowknife area. NTPC has noted that restricted space constraints at the Jackfish plant site may prevent cost effective installation of storage and vaporization facilities as required specifically for LNG, noting the need to address code required clearances between LNG storage and adjacent facilities. However, integration of LNG into this existing thermal power generation site would avoid added costs needed to establish a new thermal generation site. LNG integration into the existing site would also facilitate cost-effective conversion of diesel to gas fuel generation (including providing options for blended fuel retrofit applications with other existing diesel units) with potential other applications for boil off gas use in the existing facilities when heating is required at times when there is no diesel or natural gas generation.

- At this time, NTPC indicates no expected near-term requirement for new capacity or for replacement of existing diesel capacity at the Jackfish plant.[33] However, the recent 2014-2015 drought and concurrent hydro Snare hydro unit overhaul lead to unplanned extended operation of diesel units that may accelerate major overhaul and/or retirement assessment for other existing diesel units. Retirement of diesel units as well as requirements for new firm winter capacity at Yellowknife would create opportunity for potentially cost-effective installation of initial new natural gas generation capacity on the North Slave grid. This could facilitate establishment of an LNG supply chain to the North Slave, as well opportunities for blended natural gas and diesel fuel operation of retrofitted existing diesel units that remain on this grid.

- LNG implementation is physically feasible within the near term (e.g., within 2 to 3 years, if needed), based on LNG supply availability in BC and Alberta, equipment availability, and the limited time requirements for planning, permitting, procurement and construction. Units are scalable, with dual fuel (LNG/diesel) options.

- LNG is assumed for this study to provide a fuel expense saving of about 25% compared to diesel fuel, e.g., a saving of $0.055/kW.h on a new engine or $0.060/kW.h compared to the existing engines, based on the diesel fuel price of about $0.88/litre. The implied delivered

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[33] Information initially provided for this Study (see Attachment 1) indicated that two Mirrlees units installed in 1971/1972 at the Jackfish plant, each with 5.180 MW capacity, were at end-of-life, and that NTPC's retirement/replacement schedule indicated that one unit would need to be replaced in 2016, and the second unit would need to be replaced in 2018. NWT PUB Decision 15-2015 on December 15, 2015 approved NTPC purchase of 5x1.15 MW modular diesel units as temporary back-ups for the first Mirrlees unit retirement, i.e., these modular units can be redeployed or sold as required (see Attachment 1). NTPC has recently indicated that the first Mirrless unit has now been replaced with the purchase of the new modular diesel generation and that the second unit has undergone an overhaul which will potentially extend its life for up to 20 years.

fuel cost for LNG in the context of the Default Option diesel generation costs assumed in this assessment is approximately $0.164/kW.h (displace diesel from new engine) to $0.18/kW.h (displace diesel from existing engines).[34]

The following preliminary assessments of the LNG option are provided for the two load scenarios that are being reviewed for other infrastructure options:

- Base Case Load Scenario: If LNG displaces 5 to 10.5 GW.h/year of diesel for 20 years, the 20-year present value fuel cost saving (assuming NTPC real cost of capital of 3.926% net of inflation) compared with diesel is about $4 to $8 million (2015$). Feasibility for LNG at this low level of diesel use would depend on the incremental capital cost compared with diesel to secure these savings (which will be affected by timing requirements for diesel unit retirements, and also may be affected by ability to implement LNG at the Jackfish power site versus requirement to develop a new thermal generation site), as well as on resolution of the challenges noted regarding LNG storage life and boil off gas. These specific matters will require further feasibility assessment investigations.

  The potential capability of 10 MW of LNG capacity to displace diesel generation under Base Case load is shown by review of Figures 10 and 11. In summary, 10 MW of LNG capacity could potentially displace all diesel required even in the worst water year for the 2016 Base Case load; further, only a small amount of additional natural gas capacity would be required (through retrofitted existing diesel units or new natural gas units required in the future) to displace all of the diesel required in the worst water year for the 2035 Base Case load.

- Load Scenario with New Mine Connections: Under a load scenario with connection of an 80 GW.h/year new mining generation load in 2020, system diesel generation was estimated to average 33.8 GW.h/year with minimum fuel and other O&M costs estimated at approximately $80 million present value to 2035 (2015$). If LNG displaces this diesel at 25% fuel cost saving, the fuel cost saving present value to 2035 would approximate $19 million (2015$). Feasibility for LNG at this level of diesel use would depend on the incremental capital cost compared with diesel to secure these savings. Review of Figure 10 suggests that 10 MW of LNG capacity could potentially displace all diesel required in all but three water years for the 2020 New Mine Scenario load (and that about 20 MW of natural gas capability could be required to displace all diesel required in the worst water year).

Incremental PV cost estimates compared to Default Option diesel are not currently available for LNG options, but will be limited to facilities not otherwise required for diesel generation. Figure 15

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[34] An NTPC cost estimate from mid-2013 estimated LNG delivered fuel cost to Yellowknife in the range of $0.14 to $0.17 per kW.h, assuming natural gas price in the range of $3 to $4 per GJ. Recent (late 2015, early 2016) AECO natural gas prices have generally been in the $2.00 to $2.50 range.

below summarizes the range of present value fuel cost savings benefits estimated for the LNG option with the Base Case load and the New Mine Scenario load[35], highlighting the potential range of affordable incremental capital costs that could be incurred to establish the added LNG storage and vaporization facilities needed for LNG adoption compared with the Default Option diesel generation.

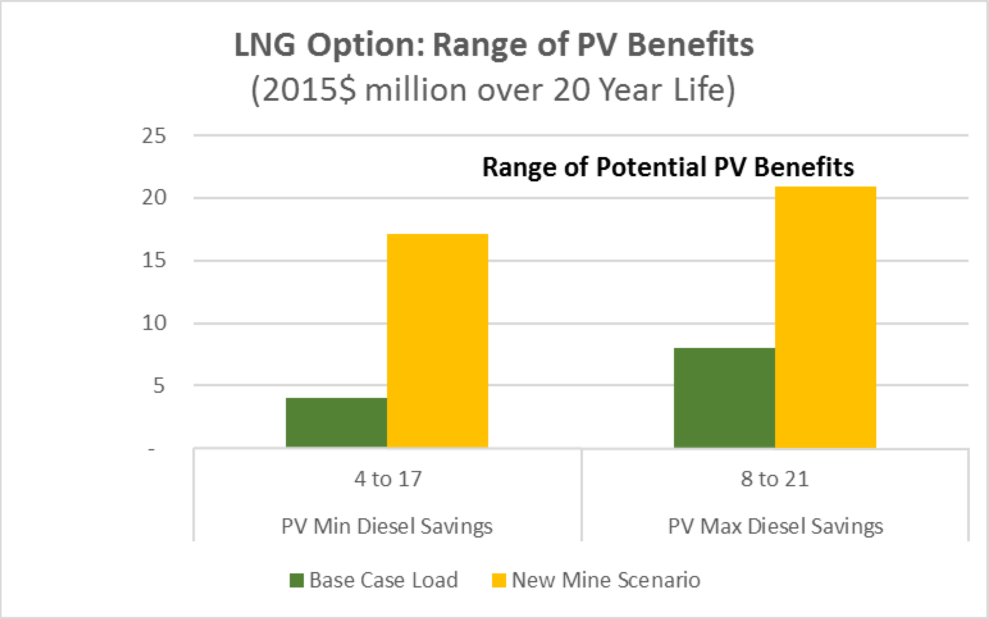

Figure 15: Range of PV Benefits for LNG Resiliency Option

In summary, this initial screening confirms the potential affordability of an LNG option relative to the Default Option diesel generation for near term implementation in or near Yellowknife, subject to timing for retirement of existing diesel units and resolution of other factors noted earlier. The LNG option is also available to facilitate near-term expansion of grid load by connection of existing and/or new mines (see "grid expansion options" below).

As with other infrastructure options such as wind, LNG option opportunities are greatly enhanced by near-term connection of even one new mine. In the case of LNG, however, this option would very likely secure overall customer cost savings compared to Default Option diesel with grid loads similar to (and perhaps considerably less than) the New Mine Scenario load.

Establishment of such an LNG option would facilitate: new thermal generation capacity to enhance system reliability; potential retrofit of at least some of the other existing North Slave diesel units to utilize natural gas; enhanced potential to proceed with at least a range of possible North Slave grid expansion options (see below); and the potential for facilitating other local Yellowknife and region

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[35] The New Mine Scenario savings range is +/-10% of the $19 million (2015$) estimate provided for the scenario.

heating and/or transportation uses of natural gas. The LNG option therefore offers near-term opportunities to enhance North Slave system resiliency through materially reducing fuel costs otherwise required for diesel generation requirements that fluctuate in response to water conditions, loads and "must run" thermal generation requirements.

Feasibility planning studies would be required to assess any specific LNG option scenario in order to confirm feasibility to reduce Default Option diesel generation costs.

2.3.7 Other Infrastructure Resource Planning Options - Grid Expansion

NTPC and/or GNWT have examined other infrastructure resource planning options such as demand side management (DSM) and grid expansion options.

For the purpose of this resiliency study, no information has been provided to suggest that DSM on its own will materially improve resiliency for the North Slave system. In contrast, grid expansion if developed could materially improve overall grid loads and new infrastructure generation option development, as well as utilize (potentially fully) the existing and projected surplus hydro generation.

With regard to grid expansion options, past studies have concluded that transmission extensions to link the North Slave and Taltson hydro grid and southern jurisdictions would require capital costs well over $1 billion, which GNWT stated was beyond its financial capacity (GNWT Response to 2014 NWT Energy Charrette Report).

However, partnership with existing and/or new mines has also been explored on its own to expand load solely on the North Slave system. North Slave grid expansion in effect assumes a grid load forecast scenario well beyond the Base Case - and it offers the opportunity for connection of new mine loads that are also well beyond the New Mine Scenario examined in this study (see Figure 9). As noted earlier, North Slave grid expansion would provide an opportunity to pursue larger scale LNG facility development at Yellowknife and/or new renewable generation development. Absent such connections to the hydro grid, these existing and/or new mines are required to rely almost entirely on diesel generation as the primary source of electric power with its higher costs and GHG emissions.

In summary, North Slave grid expansion options offer near term opportunities to secure potential benefits related to:

- Affordability (fuel cost savings due to use of surplus hydro as well as LNG, and opportunity to develop other hydro generation projects such as La Martre Falls, which would enhance hydro generation and get the community of Wha Ti off diesel);
- Environment (reduced GHG emissions, enhanced use of hydro surplus, opportunity to develop new hydro generation and get a community off diesel generation);

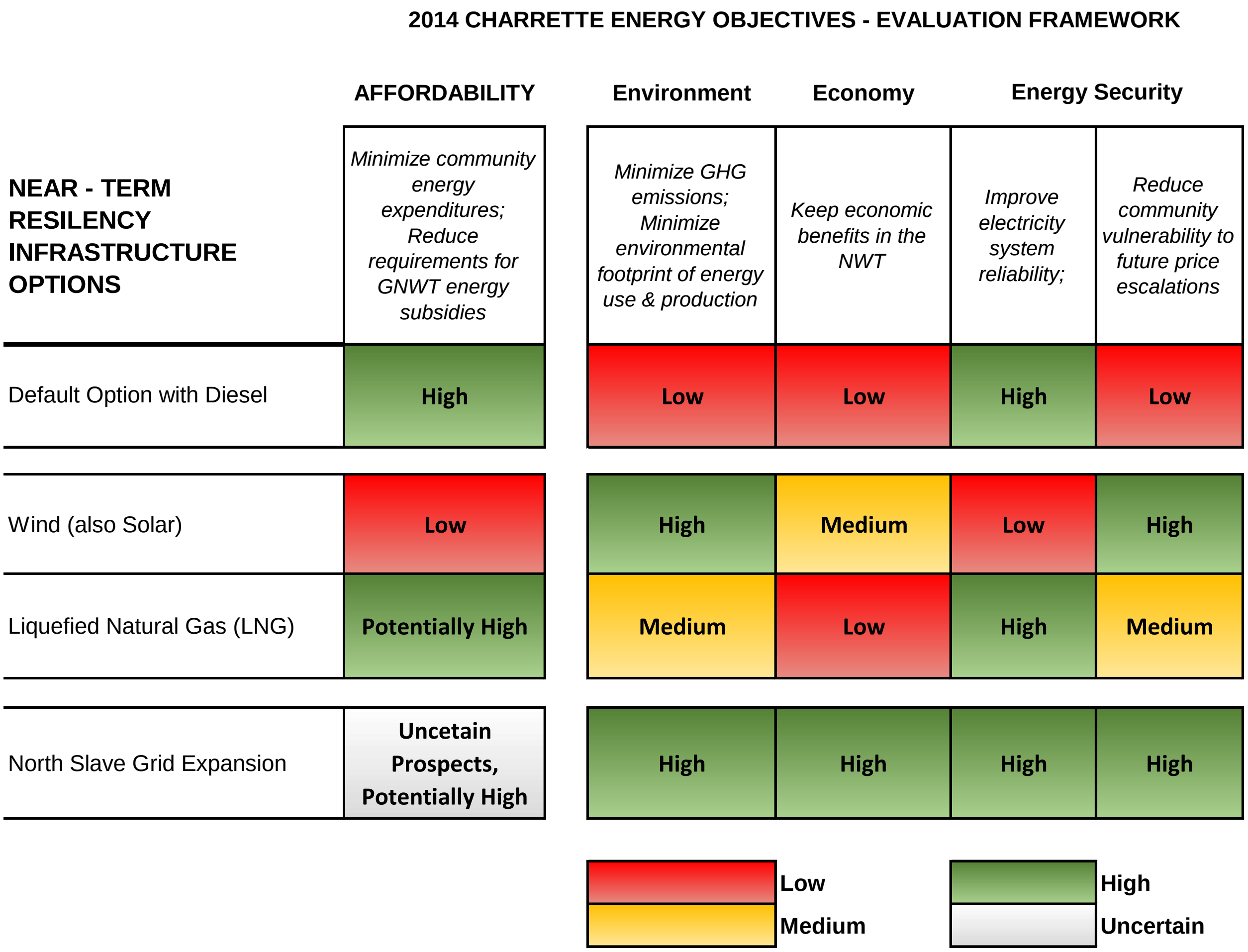
- Energy security (enhanced back up, new generation, reduced vulnerability to future price escalations relative to diesel); and
- Economy (NWT benefits related to construction and operation of an expanded grid, including any benefits that the option provides facilitating new mine development and/or longer lives for existing mines).

North Slave grid expansion options are each dependent on specific factors that need to be assessed in future as to feasibility and timing (including potential connection of the Wha Ti diesel community or development of new hydro facilities such as La Martre Falls), and vary as follows for existing versus new mines:

- Connection scenarios for any of the four existing diamond mines require near term action (i.e., connection as soon as possible before remaining mine lives are too short to support any such initiative) and are sensitive to near-term policy assessments as to the value and range of feasible approaches for such action. Snap Lake (which recently was placed on care and maintenance) and the currently being developed Gahcho Kue Mine are the closest to the grid (i.e., within about 270 km) and, when operating, would together have an annual energy load of about 140 GW.h (see Table 4).
- Connection scenarios for the four potential new mines within 100 km of the grid depend on the development timing for each new mine. The Nico mine, which has had various discussions with NTPC about terms for grid connection, would have an annual energy load of about 84 GW.h for at least 15 years (see Table 4).

2.3.8 Summary Comparison of Infrastructure Resiliency Options

Figure 16 provides a high level comparison, based on the 2014 Charrette energy objectives, of the near-term infrastructure resiliency options examined in detail above. It excludes other options (e.g., various hydro system development options), which were concluded not to be candidates today for near term action and/or further examination as regards this study's assessment of near-term resiliency options for the North Slave. Figure 16 highlights the importance attached in the 2014 Charrette report and GNWT response to "affordability" and options that minimize overall costs for GNWT subsidies and communities - and how this study has used diesel generation with the Default Option to compare the affordability of the near-term options. Figure 16 also notes options where there is "potential" high benefit on affordability, signifying that further feasibility assessments and/or other strategic development considerations must be addressed.



2014 CHARRETTE ENERGY OBJECTIVES - EVALUATION FRAMEWORK

	AFFORDABILITY	Environment	Economy	Energy Security	
NEAR - TERM RESILENCY INFRASTRUCTURE OPTIONS	*Minimize community energy expenditures; Reduce requirements for GNWT energy subsidies*	*Minimize GHG emissions; Minimize environmental footprint of energy use & production*	*Keep economic benefits in the NWT*	*Improve electricity system reliability;*	*Reduce community vulnerability to future price escalations*
Default Option with Diesel	High	Low	Low	High	Low
Wind (also Solar)	Low	High	Medium	Low	High
Liquefied Natural Gas (LNG)	Potentially High	Medium	Low	High	Medium
North Slave Grid Expansion	Uncetain Prospects, Potentially High	High	High	High	High

🟥 Low
🟨 Medium
🟩 High
⬜ Uncertain

Figure 16: High Level Comparison of North Slave Near-Term Infrastructure Resiliency Options

The "affordability" comparisons in Figure 16 reflect the material hydro generation surplus that is forecast for the North Slave over the next 20 years under the Base Case forecast and all water conditions other than extreme low water anticipated to occur in 3 to 4 years out of 31 water years. Under the Base Case load forecast potentially feasible infrastructure options to enhance resiliency are limited to diesel unit maintenance (to address reliability concerns and facilitate optimum hydro system operation) and replacement when required, Bluefish rehabilitation (that is currently at the planning stage), and assessment of potential opportunities for LNG displacement of diesel generation.

The "affordability" comparisons in Figure 16 also reflect the extent to which North Slave grid expansion options (which remain uncertain today, and were assessed assuming the New Mine Scenario with only one new mine connected by 2020) could materially affect affordability comparisons of LNG versus other near-term renewable infrastructure options such as wind. Grid expansion to connect existing or new mines is noted to have many potential benefits through use of the hydro surplus to reduce fossil fuel generation at each mine site, and through enhancing greatly the opportunity to implement LNG opportunities to reduce Default Option diesel generation fuel costs and GHG emissions. However, the New Mine Scenario grid expansion to connect one mine does not appear to be sufficient to enable wind or solar to be less costly than the Default Option diesel (let alone less costly than the lower cost LNG option).

2.4 NON-INFRASTRUCTURE RESILIENCY OPTIONS

Rate structure and other non-infrastructure resiliency options (e.g., government funding options) focus on funding utility cost instabilities. In the case of NTPC and the North Slave system today, with no major operating mine loads connected to the grid, the major utility cost instabilities arise from thermal generation cost fluctuations.

NTPC rates are approved by the NWT PUB based on forecast revenues required to recover approved forecast costs, including forecast thermal (diesel or natural gas) generation costs. Thermal generation costs can vary materially from approved forecasts due to shifts in grid loads, changes in fuel prices, or changes in thermal generation requirements due to supply failures, outages, maintenance and overhaul requirements, and fluctuations in hydro generation due to fluctuations in water availability.

- Fuel price changes are typically addressed in NWT and other jurisdictions through rate rider funds (whereby fuel price change costs or savings are passed on to ratepayers in a timely manner with some smoothing of effects over time).
- Fuel costs related to capital projects are typically included in the overall capital cost and amortized over the life of the project; similar provisions may apply for at least major overhaul related fuel costs, while planned maintenance fuel costs can be included in approved forecasts.
- Fuel costs related to at least some unplanned outages may be addressed through insurance or equivalent funding provisions (including compensation when an external party causes the interruption).
- Impacts on thermal generation from load fluctuations per se are often seen as a utility risk that can be addressed through rates.
- Based on all of the above considerations, the key material fluctuation in NTPC thermal generation costs from approved costs that remains to be addressed is the impact from changes in water availability. As shown in the last two years, the impact from this specific cost fluctuation to cause actual hydro generation capability to fall well below LTA in these

years can be sudden and severe, even under situations when there is a significant hydro generation surplus under LTA water availability.[36]

In broad terms, there are two non-infrastructure resiliency options to address the impact of thermal generation cost changes on the North Slave system due to changes in water availability (see Attachment 4):

- Rate related options (where NTPC customer rates deal with these impacts), and
- GNWT subsidy options (where GNWT funds adverse impacts of severe drought).

2.4.1 Rate Related Resiliency Options

Thermal generation cost changes due to water availability fluctuations are one of the basic cost realities of any hydro system, and the adverse impacts from such cost changes can be particularly severe on an isolated hydro system such as the North Slave due to the absence of lower cost options to acquire thermal energy from other jurisdictions. Accordingly, these costs should normally be reflected in rates along with all other basic costs required to supply reliable electricity supply.

Central issues with thermal generation cost changes related to water availability for hydro generation include the following:

- Although material thermal cost changes over a long-term period can be predicted based on available water records, the timing is typically not predictable when filing any specific NTPC GRA and the potential range of cost impacts may also vary from past experience due to a host of factors.
- The severe ranges of these cost changes would, if tracked as they occur in customer rate changes, lead to severe rate instability plus a need to apply some rate changes well beyond the time period of the cost change, e.g., the added NTPC diesel costs arising from the latest two year North Slave drought would (if collected through rate changes) require multiple years of added rate charges beyond the drought period in order to avoid severe and unacceptable rate shock.
- Due to infrequency and timing uncertainty of droughts plus the pressure to keep utility rates as low as possible, anticipated severe added thermal costs due to a drought may tend to be ignored until they actually occur - which, in turn, further aggravates the rate related

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[36] In the calendar year 2015 as updated for actual loads to the end of November, North Slave load was low (about 190.4 GW.h/year) relative to overall system hydro long-term capability and LTA hydro ability to supply this specific load which approximated 187.7 GW.h, i.e., LTA diesel requirement for this load approximated 2.7 GW.h/year. Actual hydro generation capability in 2015 based on actual water conditions dropped to only 125.3 GW.h or 67% of the LTA for the load requirements.

problems of dealing with these major added thermal costs when severe low water conditions actually occur.

Planning assessments for new hydro facilities address these issues by focusing on both the range of potential impacts and the long-term average (LTA) energy generation from the hydro facilities (and the resultant LTA ability to displace diesel or other costly thermal generation that would otherwise be required).

As reviewed in Attachment 4, rate related structures can also be designed to address the basic realities associated with a hydro-based system. In response to the above issues, rate impacts for existing hydro facilities can be planned assuming LTA hydro energy generation (rather than the energy generation assuming current or forecast year water availability) combined with appropriate rate stabilization funds (RSFs) as demonstrated by experience in other jurisdictions, i.e., the term "RSF" is not meant here to reference the specific rate stabilization fund in place today for NTPC,[37]

The long-term "rate stabilization fund" approach best reflects what should normally be assumed when the hydro facilities are being planned and developed. Under this approach, the following basic elements are required:

- For each GRA when rates are set for customers, the LTA level of hydro and thermal generation requirement needs to be estimated for the forecast load, and rates need to be approved to reflect the LTA thermal generation cost requirement. [Forecast diesel costs would also provide separately for any other non-water related diesel generation requirements, e.g., maintenance, outages, capital works, etc., which will be ignored when assessing actual diesel generation for RSF purposes.]
- An ongoing "rate stabilization fund" or RSF also needs to be established to smooth out the rate impacts on utility ratepayers over all of the years of the water cycle.

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[37] RSFs in various forms have been implemented in many hydro-based jurisdictions (see some examples below). RSFs as discussed in this study and in Attachment 4 refer to a potential fund to address water variability impacts on thermal generation costs, and not to the specific RSF in place today for NTPC.
NTPC experience with such funds first occurred in the era of the 1994 drought; however, the current NTPC rate stabilization fund applies to a wide range of instability factors beyond water availability and also is not designed to have an ongoing balance to address drought impacts.
In contrast, Yukon Energy Corporation has recently had YUB approval for an updated Diesel Contingency Fund (DCF) designed specifically and solely to address ongoing impacts on thermal generation costs from water variability with a fund cap of +/-$8 million.
Manitoba Hydro plans rates so as to have funds available to deal with low water years (equity is the "fund" in this instance, reflecting in part a non-rate base form of rate regulation and other factors specific to this utility’s history).
Newfoundland Hydro operates another form of rate stabilization which, with its own complexities, has limited useful relevance to the NTPC situation.

- During periods of above average water availability the actual thermal generation needed to meet grid load will be less than the LTA thermal generation requirement used to set customer rates, and cash cost savings will occur for the utility. However, the utility will be required to pay into the RSF in trust (i.e., the funds cannot be appropriated for other uses) all of these cost savings in thermal generation costs compared to the LTA; in this manner, these savings are set aside for the future benefit of ratepayers and do not benefit the utility shareholder.
- During periods of below average water availability the actual thermal generation costs needed to meet grid load will be more than the LTA thermal generation requirement used to set customer rates, and added cash costs will occur for the utility beyond costs provided for in rates. The utility will charge all of these added costs to the RSF, rather than to the shareholder.
- The RSF is intended to accommodate the major swings in thermal generation costs due to changes in water availability. However, caps may establish limits on the positive and negative balance of funds in the RSF, i.e., after a cap is reached, a rate rider rebate or charge will be applied to customers as required to rebate surplus funds or to restore funds as required for the RSF.
- Ideally, the RSF will balance itself over the many years in a water cycle - however, in practice many factors (including the timing of when a fund is established and the caps used) can result in a continuing need to address sudden rate impacts over multiple years - albeit that such rate impacts are normally muted compared to what would have been needed without the RSF.

Table 6 provides RSF examples for the North Slave assuming three different grid loads (194 GW.h/year, 224 GW,h/year and 295 GW.h/year) and the 31 water years previously reviewed from 1985 to 2015. No caps are assumed for the RSF examples in Table 6. Figure 17 summarizes the related volatility of Default Option annual diesel fuel and variable O&M costs at each of these three different grid loads. Water flow variability is shown to cause high diesel costs in about 10% to 18% of the flow years at Base Case forecast loads.

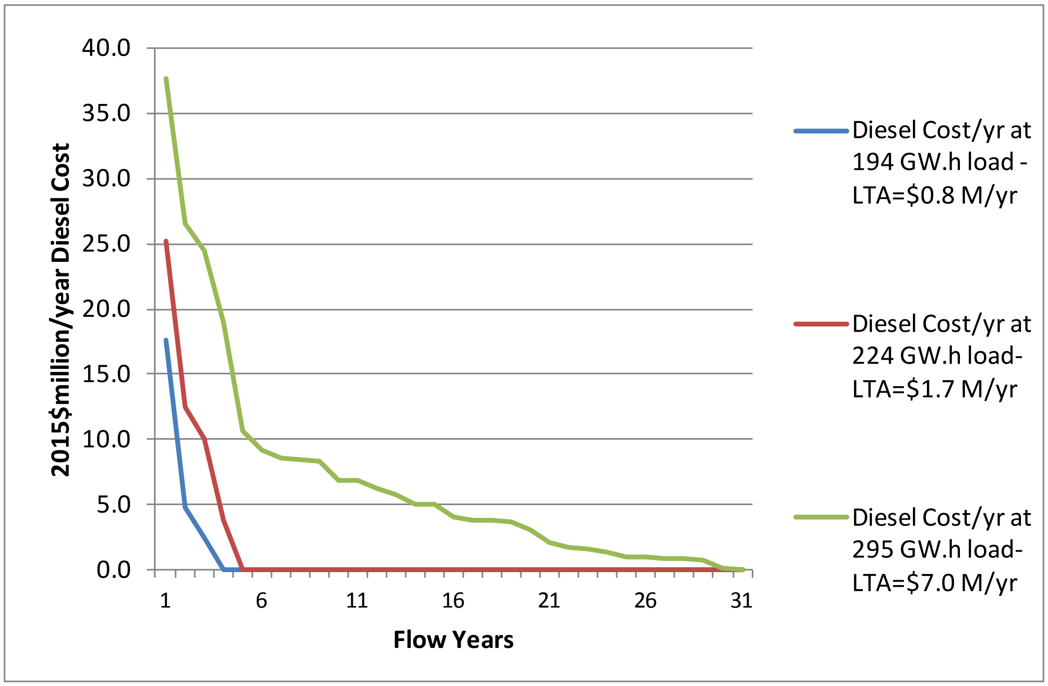

Figure 17: North Slave Diesel Operating Cost Variance over 31 Water Years at Different Loads

The LTA diesel generation (and related annual cost in rates) varies with each assumed grid load. At a grid load of 194 GW.h/year, reflecting current Base Case conditions, the LTA diesel is estimated at 3.1 GW.h/year - and at an assumed diesel fuel and O&M cost of $0.256/kW.h, an LTA diesel cost of $0.798 million/year would be included in rates[38]. In contrast, at a grid load of 295 GW.h/year (reflecting the load scenario with a new mine in 2020, which would include the impact of all additional revenues from this added load), the LTA diesel is estimated at 31.8 GW.h year with a cost of $7.0 million/year.

Assuming that the grid load and diesel cost per kW.h remain constant, Table 6 shows how diesel costs could surge above the LTA in specific water years and how the RSF would change each year to accommodate changes in hydro generation due solely to changes in water availability over the 31 water years. Over the full assumed range of water conditions, the RSF is also shown to balance out at zero - with maximum RSF positive balances ranging from about $18 million (for the lowest assumed load) to about $57 million (for the highest assumed load).

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[38] The overall impact of rates would approximate 2% from including $0.8 million/year to cover 3.1 GW.h/year of LTA diesel generation (versus the 1.2 GW.h of diesel generation currently included in rates). Based on the past record, the actual diesel costs due to water flows at the Base Case load may only occur in 3 of 31 water years.

The underlying assumption for the RSF approach shown in Table 6 is that customers are required in any event to pay for these diesel fuel and O&M costs - and that the RSF is adopted simply to smooth out these rate impacts over the full water cycle for purposes of rate stability, predictability and fairness for customers over the planning period. The RSF allows rates to be set based on LTA, subject to the RSF provisions for fund caps and other factors that may still affect outcomes.

	RSF assuming 194 GW.h/year load			**RSF assuming 224 GW.h/year load**			**RSF assuming 295 GW.h/year load**		
Water Year	**Default Option diesel**	**RSF Annual Impacts (diesel at $0.256/kW.h)**	**RSF Balance**	**Default Option diesel**	**RSF Annual Impacts (diesel at $0.256/kW.h)**	**RSF Balance**	**Default Option diesel**	**RSF Annual Impacts (diesel at $0.222/kW.h)**	**RSF Balance**
	GW.h/yr	2015$million	2015$million	GW.h/yr	2015$million	2015$million	GW.h/yr	2015$million	2015$million
1985	0.0	0.798	0.798	0.0	1.663	1.663	4.32	6.091	6.091
1986	0.0	0.798	1.596	0.0	1.663	3.326	3.79	6.209	12.301
1987	0.0	0.798	2.394	0.0	1.663	4.988	25.95	1.290	13.591
1988	0.0	0.798	3.192	0.0	1.663	6.651	17.27	3.217	16.808
1989	0.0	0.798	3.990	0.0	1.663	8.314	7.23	5.444	22.252
1990	0.0	0.798	4.789	0.0	1.663	9.977	14.11	3.918	26.170
1991	0.0	0.798	5.587	0.0	1.663	11.640	9.71	4.894	31.065
1992	0.0	0.798	6.385	0.0	1.663	13.302	16.42	3.405	34.470
1993	0.0	0.798	7.183	0.0	1.663	14.965	18.17	3.016	37.486
1994	0.0	0.798	7.981	0.0	1.663	16.628	47.99	-3.604	33.882
1995	18.6	-3.955	4.026	48.6	-10.770	5.858	119.57	-19.493	14.389
1996	0.0	0.798	4.824	0.0	1.663	7.521	41.57	-2.179	12.210
1997	0.0	0.798	5.622	0.0	1.663	9.183	6.18	5.678	17.888
1998	0.0	0.798	6.420	0.0	1.663	10.846	38.50	-1.497	16.390
1999	0.0	0.798	7.218	0.0	1.663	12.509	3.29	6.319	22.709
2000	0.0	0.798	8.017	0.0	1.663	14.172	7.75	5.330	28.039
2001	0.0	0.798	8.815	0.0	1.663	15.835	4.71	6.006	34.045
2002	0.0	0.798	9.613	0.0	1.663	17.497	22.70	2.011	36.056
2003	0.0	0.798	10.411	0.0	1.663	19.160	22.52	2.051	38.107
2004	0.0	0.798	11.209	14.7	-2.103	17.057	85.71	-11.977	26.130
2005	0.0	0.798	12.007	0.0	1.663	18.720	30.78	0.216	26.346
2006	0.0	0.798	12.805	0.0	1.663	20.383	0.00	7.050	33.397
2007	0.0	0.798	13.603	0.0	1.663	22.046	17.18	3.235	36.632
2008	0.0	0.798	14.401	0.0	1.663	23.708	37.28	-1.226	35.406
2009	0.0	0.798	15.199	0.0	1.663	25.371	0.57	6.924	42.330
2010	0.0	0.798	15.998	0.0	1.663	27.034	28.22	0.786	43.116
2011	0.0	0.798	16.796	0.0	1.663	28.697	30.87	0.196	43.312
2012	0.0	0.798	17.594	0.0	1.663	30.360	3.87	6.192	49.504
2013	0.0	0.798	18.392	0.0	1.663	32.022	38.18	-1.427	48.077
2014	9.4	-1.610	16.782	39.4	-8.426	23.597	110.41	-17.460	30.617
2015 adj	68.7	-16.782	0.000	98.7	-23.597	0.000	169.67	-30.617	0.000
31-year av.	**3.1**	**0.0**	**8.8**	**6.5**	**0.0**	**15.3**	**31.8**	**0.0**	**28.0**
Annual Diesel ($)		**0.798**			**1.663**			**7.050**	

Table 6: RSF Examples with 31 Water Years and Different North Slave grid loads

As noted, many factors can in practice affect the operation of an RSF of the type assumed in Table 6, including timing when it is established (relative to water year conditions), actual grid loads, approved thermal generation costs per kW.h, and any caps approved for the RSF. Table 6 assumptions, for example, never show the RSF with a negative balance - however, if the RSF was assumed to begin with 2014 and 2015 water conditions (rather than 1985 water conditions), clearly a large RSF deficit would initially be required and this deficit would take a long time to pay down.

In summary, rate structure resiliency options can be applied to smooth out the impacts of hydro generation capability changes due to changing water conditions. To be effective, such options need to include in rates the applicable LTA thermal generation costs (without regard to actual GRA time period water conditions) for the forecast grid load, and also to establish an effective RSF mechanism that allows funds to be retained in an RSF as required to address the added thermal generation costs incurred during extreme low water conditions.

The 31-year water record for the North Slave examined in this study shows low water conditions occurring approximately once every decade. Given that the recent drought impact has started to be alleviated with recovered flows in late 2015 and improved snow water equivalent levels in January 2016, an opportunity would appear to exist for establishing an appropriate RSF mechanism for the North Slave with a potential timing advantage similar to that assumed in Table 6, i.e., with the potential opportunity (but no certainty) to accrue funds in the RSF for several years prior to the next material low water event.

2.4.2 GNWT Subsidy Options

Non-infrastructure resiliency options to date for the North Slave system have included GNWT subsidy of $48 million added diesel costs required to address the impact of extreme drought conditions that started in 2014. As reviewed earlier (see Table 2), recent updates have reduced this forecast GNWT cost to about $28 million.

Recent GNWT subsidies reflected the absence in existing rate structures or mechanisms that could adequately address the impact of these recent drought conditions.

In response to a severe drought when no adequate RSF is in place to assist in funding the near term surge of added costs, GNWT as owner of NTPC can at a minimum assist in the arrangement of added debt financing that may be needed by NTPC to fund the major increase in thermal generation fuel and other O&M costs. Provision for such debt financing measures would provide NTPC with resiliency as regards any near term financing requirements without concurrently having GNWT (rather than ratepayers) ultimately taking responsibility for these added thermal generation costs. The timing for repayment of such financing could be based on the principles reviewed above for rate related resiliency options (assuming that ultimate cost recovery would be required from ratepayers).

Beyond provision of debt financing, it will be important for NTPC and the NWTPUB to be informed of GNWT policy regarding rate related resiliency options versus any GNWT subsidies for future North Slave drought impacts. If GNWT subsidies are to be retained as an option, it will be critical that NTPC and the NWTPUB are aware of any parameters or limits with regard to such subsidies in order that they may consider and implement any appropriate rate related resiliency options.

2.4.3 Summary of Non-Infrastructure Resiliency Options

Thermal generation cost changes due to water availability fluctuations are one of the basic cost realities of any hydro system, and can be particularly severe on an isolated hydro system such as the North Slave. Accordingly, these long term average thermal costs should normally be reflected in rates along with other basic costs required to supply reliable electricity supply.

In broad terms, there are two non-infrastructure resiliency options to address the impact of thermal generation cost changes on the North Slave system due to changes in water availability: rate related options, and GNWT subsidy options.

Rate related resiliency options will remain a key requirement for a hydro-based system such as North Slave, and effective long-term measures are needed to smooth out customer rate instabilities caused by thermal generation cost changes due to changing water conditions. In summary, rate stabilization measures to smooth out the impact on customer rates of future thermal generation cost changes due to changing water conditions include the following two key elements:

1. **Rates based on long-term average requirements**: NTPC revenue requirements for the North Slave can include thermal generation costs for the forecast grid load based on hydro generation assuming long-term average water conditions. This approach will reduce the need to vary rates based on fluctuating short-term water conditions; and
2. **Dedicated Fund:** A dedicated ratepayer trust fund, with adequate upper and lower caps, can absorb annual variations in actual thermal generation costs compared to the expected long-term average thermal generation cost in customer rates.

GNWT as owner of NTPC can at a minimum assist in the arrangement of added debt financing that may be needed by NTPC to fund the major increase in thermal generation fuel and other O&M costs. Beyond provision of debt financing, it is important that GNWT inform NTPC and the NWT PUB of any GNWT policy to subsidize NTPC costs due to future North Slave droughts so that this can be fully considered in the planning of rate stabilization measures.

APPENDIX A:

Annual Hydro and Diesel Generation Summary

1.0 MAXIMIZED ANNUAL HYDRO GENERATION

Table A-1 provides the maximized annual hydro generation for each of the 31 years of water record used for the Figure 2 assessment.

			Lowest to Highest Water Years - 30-Year Simulation			Lowest to Highest Water Years - 31-Years	
Water Year	**Simulated Maximum Hydro (GW.h/yr)**		**% years not less than**	**Simulated Maximum Hydro (GW.h/yr)**		**% years not less than**	**Simulated Maximum Hydro (GW.h/yr)**
1985	290.7	1	3%	175.4	1	3%	125.3
1986	291.2	2	7%	184.6	2	6%	175.4
1987	269.1	3	10%	209.3	3	10%	184.6
1988	277.7	4	13%	247.0	4	13%	209.3
1989	287.8	5	17%	253.4	5	16%	247.0
1990	280.9	6	20%	256.5	6	19%	253.4
1991	285.3	7	23%	256.8	7	23%	256.5
1992	278.6	8	27%	257.7	8	26%	256.8
1993	276.8	9	30%	264.1	9	29%	257.7
1994	247.0	10	33%	264.2	10	32%	264.1
1995	175.4	11	37%	266.8	11	35%	264.2
1996	253.4	12	40%	269.1	12	39%	266.8
1997	288.8	13	43%	272.3	13	42%	269.1
1998	256.5	14	47%	272.5	14	45%	272.3
1999	291.7	15	50%	276.8	15	48%	272.5
2000	287.2	16	53%	277.7	16	52%	276.8
2001	290.3	17	57%	277.8	17	55%	277.7
2002	272.3	18	60%	278.6	18	58%	277.8
2003	272.5	19	63%	280.9	19	61%	278.6
2004	209.3	20	67%	285.3	20	65%	280.9
2005	264.2	21	70%	287.2	21	68%	285.3
2006	296.2	22	73%	287.8	22	71%	287.2
2007	277.8	23	77%	288.8	23	74%	287.8
2008	257.7	24	80%	290.3	24	77%	288.8
2009	294.4	25	83%	290.7	25	81%	290.3
2010	266.8	26	87%	291.1	26	84%	290.7
2011	264.1	27	90%	291.2	27	87%	291.1
2012	291.1	28	93%	291.7	28	90%	291.2
2013	256.8	29	97%	294.4	29	94%	291.7
2014	184.6	30	100%	296.2	30	97%	294.4
30-year average	**267.9**			**267.9**	31	100%	296.2
					31-year average		**263.3**
2015 adj	125.3						
31-year average	**263.3**						

Table A-1: North Slave Maximized Annual Hydro Generation by Water Year: 1985-2015

Figure A-1 shows the maximized hydro generation between 1985 and 2015. Figure 4 in Part 1 re-arranges the data from lowest to highest maximized annual hydro generation.

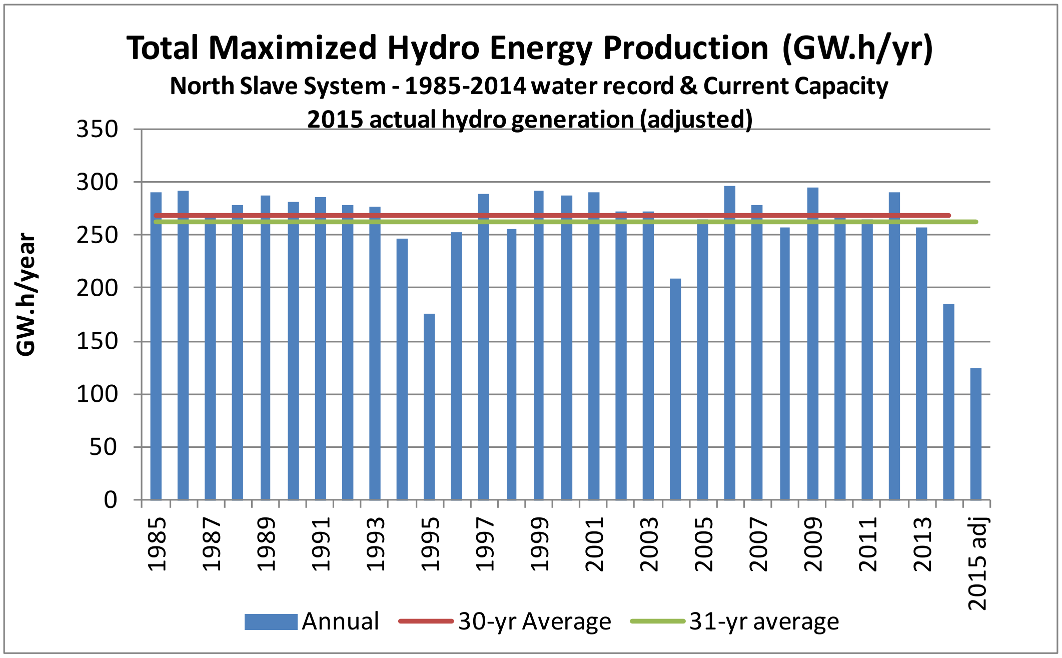

Figure A-1: North Slave Maximized Annual Hydro Generation by Water Year: 1985-2015

2.0 HYDRO AND DIESEL GENERATION AT DIFFERENT LOADS & INFRASTRUCTURE OPTIONS

Figures in this section show the use of hydro generation available over 31 water years (1985-2015) under different grid load and infrastructure option conditions. All figures assume:

- Maximum hydro generation capability in each water year as per Table A-1; and
- "Must run" diesel requirement at 3 GW.h/yr

Wind option figures assume 20 MW wind generation with 44 GW.h/yr of wind generation.

The assumed grid loads reflect the following:

- 194 GW.h/yr is Base Case load forecast for 2016 (assumes no mine connections)
- 224 GW.h/yr is Base Case load forecast for 2035 (assumes no mine connections)
- 295 GW.h/yr is Mine Scenario load forecast for 2020 (assumes Base Case load forecast plus one mine load connected to grid requiring 80 GW.h/yr of generation).

Each figure shows the number of water or flow years where spill would occur of otherwise useable hydro energy, versus water or flow years when diesel generation would be required to meet energy loads.

- Figure A-2: Default Option at 194 GW.h/yr: spill hydro energy in 28 of 31 flow years
- Figure A-3: Default Option at 224 GW.h/yr: spill hydro energy in 27 of 31 flow years
- Figure A-4: Wind Option at 194 GW.h/yr: spill hydro energy in 30 of 31 flow years
- Figure A-5: Wind Option at 295 GW.h/yr: spill hydro energy in 26 of 31 flow years

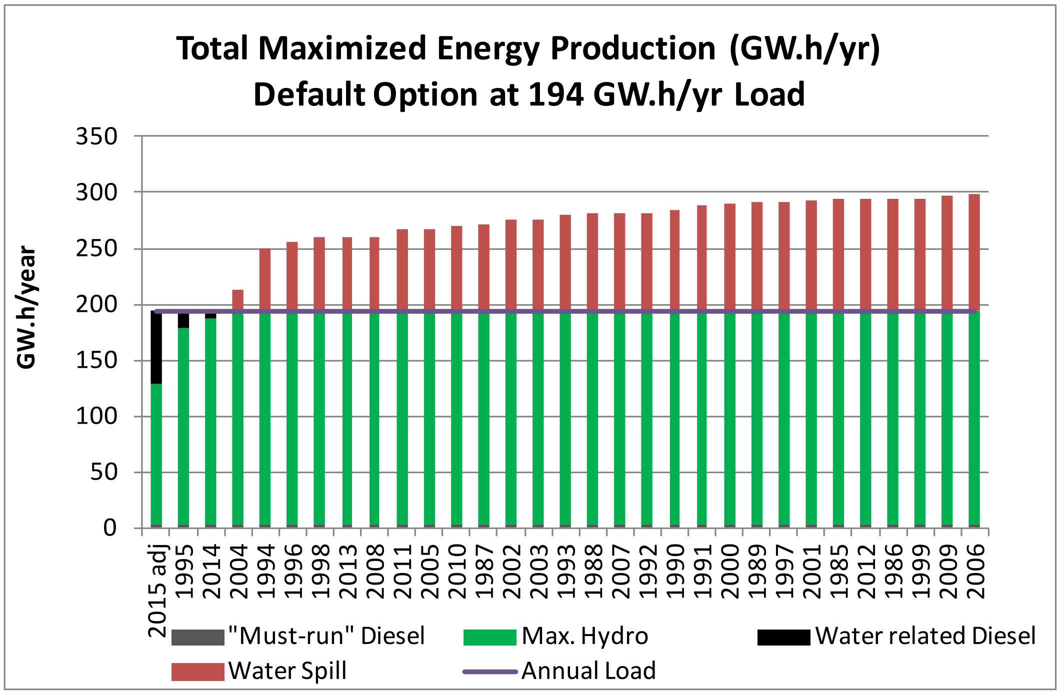

Figure A-2: Hydro & Diesel Generation at 194 GW.h/yr Load - Default Option

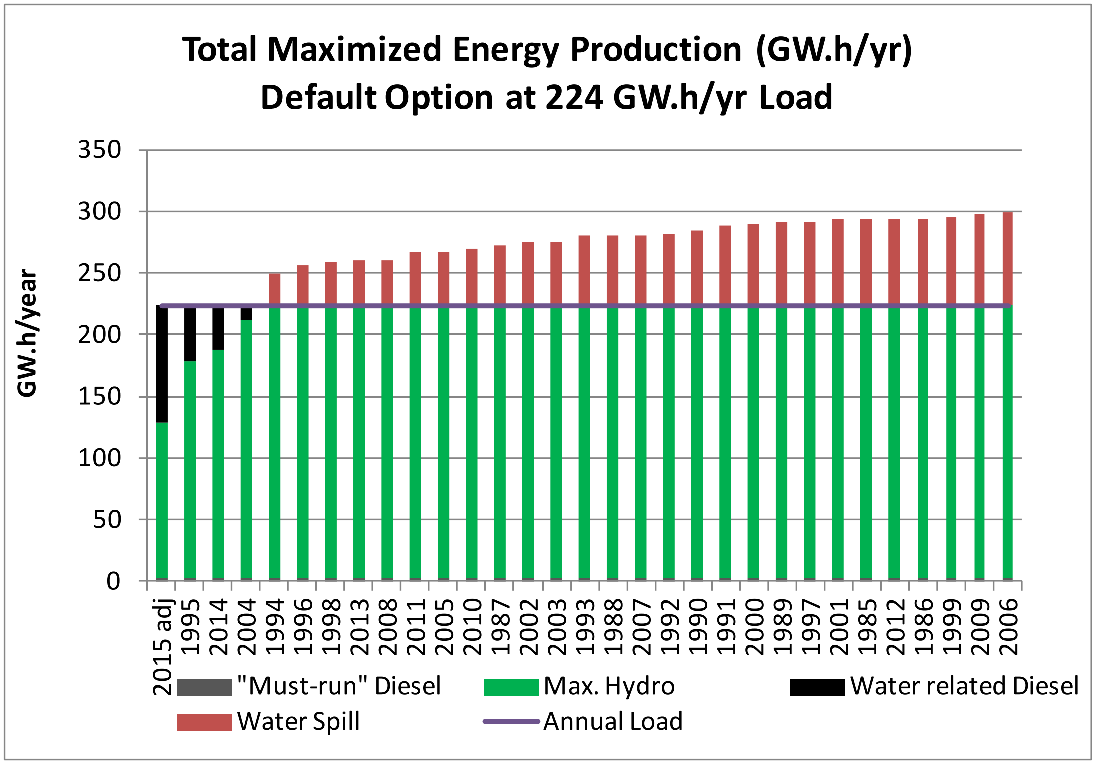

Figure A-3: Hydro & Diesel Generation at 224 GW.h/yr Load - Default Option

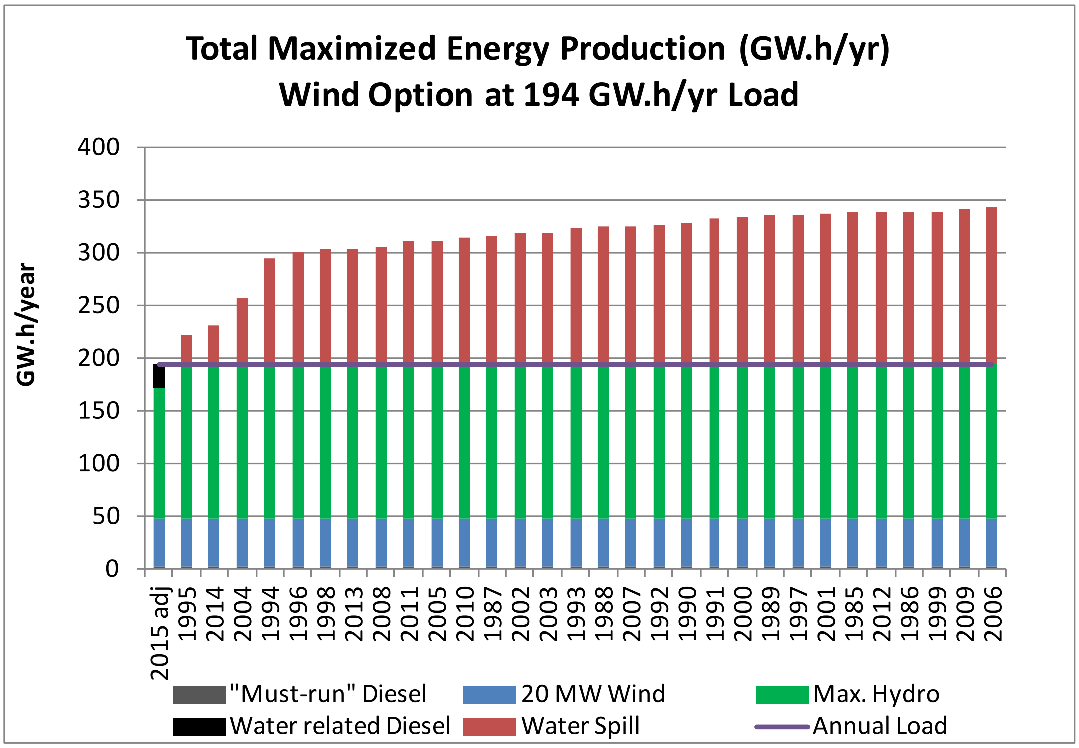

Figure A-4: Hydro & Diesel Generation at 194 GW.h/yr Load - Wind Option

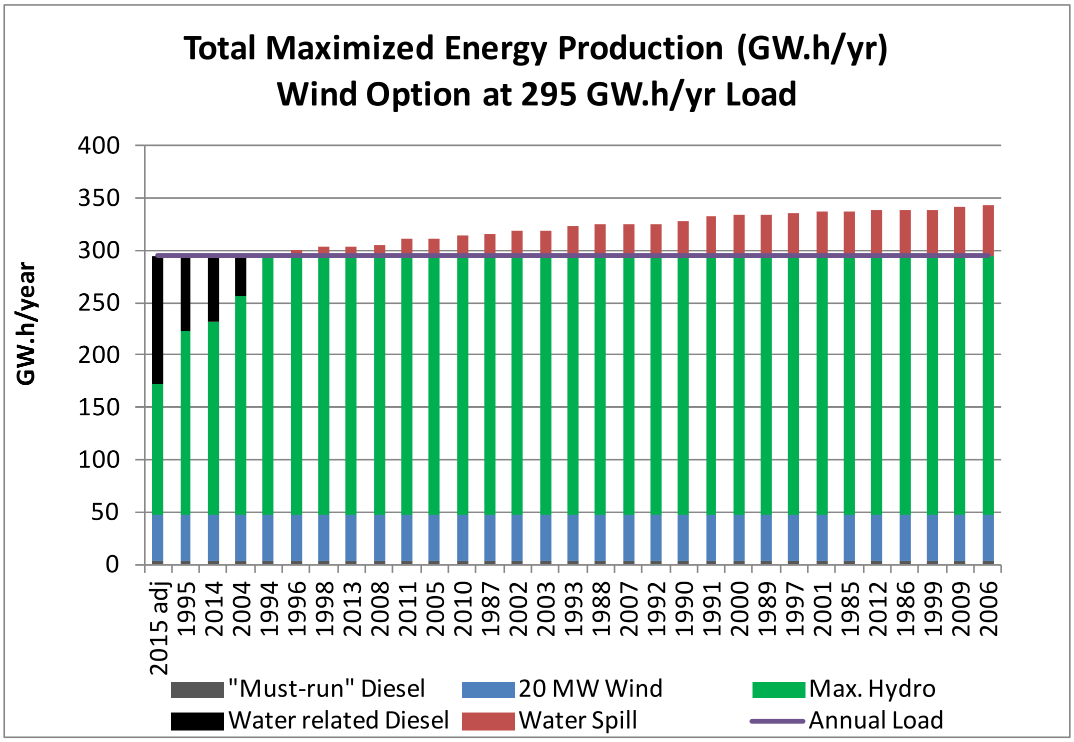

Figure A-5: Hydro & Diesel Generation at 295 GW.h/yr Load - Wind Option