YUKON ENERGY CORPORATION

APPLICATION FOR

AN ENERGY PROJECT CERTIFICATE

AND

AN ENERGY OPERATION CERTIFICATE

REGARDING THE PROPOSED

WHITEHORSE DIESEL – NATURAL GAS CONVERSION PROJECT

December 9, 2013

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1.0 INTRODUCTION

Yukon Energy Corporation ("**YEC**" or "**Yukon Energy**") hereby applies (the "**Application**") to the Minister of Justice (the "**Minister**") for an energy project certificate and an energy operation certificate (the "**Certificates**") for the proposed Whitehorse Diesel – Gas Conversion Project (the "Project"). The Project has been designated by OIC 2013/200 as a "regulated project" under Part 3 of *the Public Utilities Act*. It is understood that, as required by Part 3 of the *Public Utilities Act*, the Minister will refer this Application for the Certificates to the Yukon Utilities Board (the "**YUB**", or the "**Board**") for a review.

The Project will modernize Yukon Energy's Whitehorse Thermal Generating Station ("**WTGS"**) to meet growing requirements for reliable and flexible thermal generation on the Yukon grid, with conversion of WTGS thermal generation units scheduled for retirement from diesel fuel to cheaper burning and cleaner natural gas fuel supplied by liquefied natural gas ("**LNG**") delivered by truck from Alberta or British Columbia. Key elements of the Project include:

- To accommodate new facilities required for the Project, Yukon Energy will acquire approximately 0.9 ha of Public Utility zoned Yukon Government lands and create access and utility crossings at various locations along the 0.6 ha of privately held railway right of way adjacent to the south of the existing WTGS site (the "**Expanded Site Area**" – See Appendix A).
- The Project scope will involve replacing two diesel generating units scheduled for retirement in the existing WTGS by 2015 (9.1 MW total nameplate capacity) with up to three new modular natural gas-fired generating units (13.1 MW total capacity), and the installation of LNG truck offloading, storage, vapourization and related infrastructure on the Expanded Site Area.
- Two natural gas-fired units (8.8 MW total capacity) are anticipated to be in service before the end of Q4 2014 to provide capacity and fuel cost savings during the winter of 2014/2015.

Yukon Energy's 2011 update to its 20-Year Resource Plan: 2006-2025[1], identified the feasibility of thermal generation using LNG for near-term development (i.e., up to 2015) as it is expected to provide a reliable, abundant, low-cost, and flexible source of supply with reduced greenhouse gas emissions and costs compared to using existing diesel generation. Separate from the current Project, Yukon Energy continues to pursue potential near-term hydro enhancement projects, including Mayo Lake Enhanced Storage and Marsh Lake (Southern Lakes) Storage. For future consideration when higher long term grid loads can justify such developments, Yukon Energy is also pursuing wind development that could range up to 20 MW at Techo (formerly Ferry Hill) in the Stewart Crossing area, as well as potential future hydro generation at various potential greenfield sites.

In Yukon Utilities Board Order 2013-1 dated March 25, 2013 relating to regarding Yukon Energy's 2012/2013 General Rate Application, noted that the YUB agreed that LNG powered thermal generation, at this time, appears to be a viable project[2]. The Board also directed YEC to base its hydro and diesel

[1] This update (YEC 2011 20-Year Resource Plan: 2011-2030) was filed with the Board in July 2012 as a response to interrogatories during the Yukon Energy 2012/2013 General Rate Application.
[2] Paragraph 384 of Order 2013-1.

energy requirements on 100% long term average ("**LTA**") hydro generation for the forecast 2012 and 2013 load in its compliance filing[3]. This direction re-establishes to ratepayers and YEC during each GRA the full LTA benefit (savings to ratepayers) of changing from diesel generation costs to LNG generation costs.

A proposal for the Whitehorse Diesel-Natural Gas Conversion Project was submitted in August 2013 to the Yukon Environmental and Socio-economic Assessment Board ("**YESAB**") under the *Yukon Environmental and Socio-economic Assessment Act*, and is currently subject to a screening by the Executive Committee of YESAB. This process will lead to a recommendation by the Executive Committee, and a response by the Yukon Government in the form of a decision document. Any government authorizations issued in support of the Whitehorse Diesel-Natural Gas Conversion Project, including any Energy Project Certificate or Energy Operation Certificate under Part 3 of the *Public Utilities Act*, will have to conform to the decision document of the Yukon Government.

On November 22, 2013, the Commissioner in Executive Council designated the Whitehorse Diesel – Natural Gas Conversion Project as a regulated project under Part 3 of the *Public Utilities Act* pursuant to OIC 2013/200. As prescribed by OIC 2007/50, Yukon Energy's Application for the Certificates for the Project includes the following sections:

- Applicant;
- Project Description;
- Project Justification;
- Consultation; and
- Other Applications and Approvals.

[3] Paragraph 60 of Order 2013-1.

2.0 APPLICANT

The required information on the Applicant is as follows:

Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon, Y1A 6S7
Telephone: (867) 393-5300; Fax: (867) 393-5323; Website: www.yukonenergy.ca

The person with whom correspondence should be made respecting the Application is:

Hector Campbell, P. Eng., M.B.A.
Director, Resource Planning & Regulatory Affairs
Telephone: (867) 393-5331; Fax: (867) 393-5323; Email: hector.campbell@yec.yk.ca

3.0 PROJECT DESCRIPTION

3.1 PROJECT SUMMARY DESCRIPTION

The Project will be constructed within a developed part of the City of Whitehorse, approximately two kilometres south of downtown Whitehorse. The Project Construction Footprint includes components that will be located on Yukon Energy property, on lands to be acquired from Yukon Government and on a privately owned parcel (see Appendix A for a map of the site from the YESAB filing).

The Project scope will involve replacing two diesel generating units scheduled for retirement in the existing WTGS by 2015 (9.1 MW total capacity) with three new modular natural gas-fired generating units (13.1 MW total capacity), and the installation of LNG truck offloading, storage, vapourization and related infrastructure on the Expanded Site Area. Two natural gas-fired units (8.8 MW total capacity) are anticipated to be in service Q4 2014 to provide capacity and fuel cost savings during the winter of 2014/2015. Projected in-service for the third natural gas-fired unit (4.4 MW) will occur as required to meet grid capacity planning requirements, and is anticipated to be within a few years after the first two units are in service. The estimated capital cost (2013$) for the Project is $38.8 million, with $34.4 million for the initial phase to be completed by the end of 2014[4] and the balance of $4.4 million when the third natural gas-fired unit is installed.

To accommodate new facilities required for the Project, Yukon Energy will acquire approximately 0.9 ha of Public Utility zoned Yukon Government lands, and create access and utility crossings at various locations along the 0.6 ha of privately held railway right of way on the Expanded Site Area adjacent to the south of the existing WTGS site. The precise location of each component of the Project will be finalized upon completion of detailed engineering design and permitting by regulators following assessment under the *Yukon Environmental and Socio-economic Assessment Act* ("**YESAA**").

The Project lies within the Traditional Territory of the Kwanlin Dün First Nation ("**KDFN**") and the Ta'an Kwäch'än Council ("**TKC**"). In May 2012, TKC and KDFN were invited to become partners in assessing the feasibility of using LNG as a fuel source in Yukon and agreed to co-develop a Partnership Committee with terms of reference and signed confidentiality agreements completed July 2012. Regular partnership meetings have been held since July 2012, focused on review of the business case, establishing a good working relationship and making substantive progress toward developing economic and business opportunities for the two First Nations relative to the Project. This has also included discussion regarding a possible investment in the Project by TKC and KDFN through negotiation of a Partnership Agreement.

[4] Approximately $1.45 million of the $34.4 million for the initial phase is for decommissioning of the existing WD1 and WD2 Mirrlees units, and this work is currently expected to occur in summer of 2015.

3.1.1 Existing Facilities and Project Components

The existing Whitehorse Rapids Generating Station was built to supply electricity to the Whitehorse area beginning in 1958 and includes the following components:

- **Whitehorse hydro plants (P125 and P127)** – Located on the Yukon River, the plants combined have four generating units with a combined nameplate capacity of 40 MW.
- **Whitehorse diesel plant (P126)** – Located adjacent to the Yukon River, the plant has seven generating units with a nameplate capacity of 25 MW, with current diesel storage capacity on site of 162,000 litres.
- **Substation** – The main substation for the Whitehorse Rapids Generating Station (S150) is located within the existing site.
- **Administration offices** – Within the Whitehorse Rapids Generating Station compound there are also the main administrative offices for the Yukon Energy Corporation.

In summary, the proposed new Project components as described in Section 6.1 of the Project Proposal Submission to the YESAB Executive Committee (as revised in November 2013[5]) are as follows (see **Appendix A**):

1. **Expanded Site Area Acquisition:** Purchase of Crown land and access road and utility crossings of private land to expand the WTGS for the purposes of siting the proposed facilities.
2. **Components on Expanded Site Area:** Construction and operation of the following components on the Expanded Site Area:
    a. **LNG truck offloading, storage, and vapourization facilities and related infrastructure,** including up to three 166.5 m^3 and two 120 m^3 storage tanks, a short all weather access road from Miles Canyon Road for truck offloading and access to the components on the Expanded Site Area, vapour barrier, fencing and other facilities required for safe operation.
    b. **Three new 4.4 MW natural gas-fired modular reciprocating generating units and related facilities,** including a separate switchgear module, a fluid transfer station, and a small substation to transmit power from the new generating units to the electrical grid via S150 substation. Planned in-service for the first two natural gas-fired units (8.8 MW) is in fourth quarter 2014, and projected in-service for the third natural gas-fired unit (4.4 MW) is currently expected to occur within a few years of the installation of the first two units.

[5] The initial Project Proposal filed with YESAB in August 2013 included lease of the private land in the Expanded Site Area, initial development of four LNG storage tanks (666 m^3) and potential for additional storage tanks and engine modules in the future on this site. In November 2013, a revised plan was filed with YESAB which excluded any lease of the private lands, and provided for Project facilities located only on the Crown land portion of the Expanded Site Area or on YEC's existing property (other than access road and utility crossing of the private lands). The revised Project plan retained the three gas-fired units for the Project (two to be developed in 2014), with provision for three initial LNG storage tanks (499.5 m^3 for a total of 6 days storage) and the potential to add in future two additional smaller storage tanks (240 m^3) to retain 6 days storage with the third gas-fired module.

c. **Other Site Infrastructure,** including:

i. **New property fence and gates** constructed to limit access to the new facility to authorized personnel;

ii. **Improvement of drainage infrastructure:** Storm water will be conveyed to a new storm water retention pond or similar infrastructure located nearby. The conveyance route and location of the new retention area has yet to be determined. There are, however, several feasible options for this component including the ditch/depression located just south of the existing main gate or to a site on the west side of Robert Service Way so as to tie into the existing drainage infrastructure maintained by the City of Whitehorse. The final location and design (by an engineer licensed to practice in the Yukon) of the storm water retention pond will be determined in collaboration with the City and applicable regulators as a part of the detailed design to ensure it will be able to handle run off from the Project site and from Robert Service Way;

iii. **Blackstart power** capability for the natural gas-fired generating units[6]; and

iv. **Other related facilities,** including: natural gas, fire suppression, water and glycol/water piping, communications and electric service needed to connect the components; hydrants, streetlights, security systems and other infrastructure, and complete site landscaping as per City of Whitehorse zoning bylaws.

3. **Distribution Line and Communication Line** on the WTGS to bring power from the new generating units at 35 kV from the new small substation on the Expanded Site Area to the existing S150 substation that supplies power to the Yukon grid (and to provide power to the Expanded Site Area when the new generating units are not operating).

4. **Utility Trench** on the WTGS for an underground pipe system between the existing WTGS diesel plant and the facilities on the Expanded Site Area for:

   a. Water supply to the Expanded Site Area for fire suppression;

   b. Glycol/water heating system to make use of the heat produced by the engines located in the existing WTGS facility; and

   c. Natural gas supply for conversion of the existing oil boiler to natural gas, future conversion of existing diesel engines to fuel blend (diesel and natural gas), and/or future installation of new gas or dual fuel engines at the existing WTGS service bays previously used by diesel engines that have been removed.

[6] The new small substation in the Expanded Site Area will have quick connect capability for a standby mobile genset in the event that this is required due to loss of connection to S150. Heat to start the vapourizer will be from the glycol/common water loop that will be kept warm year round (using multiple heat sources, e.g., diesel and gas units when operating, and an electric boiler, diesel and natural gas boiler in the diesel plant) to keep diesel and gas gensets on hot standby.

5. **Decommissioning of two Mirrlees Diesel Units (WD1 and WD2) in the existing WTGS,** including ancillary equipment and disconnection from the electrical grid.

Appendix A provides a map of the Project Construction Footprint. Additional changes to site layout and related components may occur during final design of the Project, subject in each instance to the restrictions that they be confined to the YEC-acquired property area within the Expanded Site Area and the vapour barrier requirements to comply and conform with the requirements of *CSA Standard Z276-11: Liquefied Natural Gas (LNG) Production*, *Storage and Handling*, as assessed in the vapour dispersion analysis. Based on these restrictions, it is understood that any such final design changes will not affect the environmental or socio-economic effects assessment of the Project as provided in the revised Project Proposal.

Yukon Energy is undertaking all required planning, effects assessment and permitting, engineering design, procurement, contracting and other related activities to obtain authorizations and approvals necessary to allow construction of the Project to commence at the start of May 2014 to meet the in-service target of late 2014 for the first two natural gas-fired units. This schedule is driven by forecast thermal generation requirements for the winter of 2014/15, both to provide new thermal generation capacity for reliable service during that winter and to save in excess of $2.1 million[7] of thermal fuel generation costs charged to ratepayers in 2015. Cost savings resulting from the Project will benefit all of Yukon's electricity ratepayers.

New natural gas-fired engines are assumed to have an economic life of 40 years, based on expected average annual utilization of these assets. Assuming that the facilities will continue to be required for established backup capacity for the Yukon grid, it is expected that individual components will be replaced as they reach end of life and the Project facilities will not be decommissioned.

Yukon Energy has secured an LNG supply of up to 250 m^3 per day for a minimum of five years from Shell Canada's Jumping Pound LNG plant being developed near Calgary and scheduled to start operation before the end of 2014. Yukon Energy also retains the potential during the term of the Shell Canada contract to source LNG from the Fort Nelson area in northern British Columbia should additional liquefaction facilities come into service in this area, and/or Shell Canada arranges to make LNG supplies available in this area.

Truck delivery of LNG to the WTGS will use a new double trailer (A-Train) combination with a 95,000 litre capacity, although currently available Tridem units with a 54,000 litre capacity may be used initially if there are delays in the licensing and/or fabrication of the new A-Train units.

[7] Estimated based on long-term average thermal generation of more than 14 GW.h for Base Case load forecast (no Alexco) over the six month period from January 1, 2015 to June 30, 2015; reflects the difference between estimated diesel fuel cost of $4.02 million with existing diesel units (based on Yukon Energy's 2012/13 GRA Compliance Filing average diesel fuel generation cost of 28.7 c/kW.h), and $1.89 million with new LNG units (based on LNG fuel cost at 13.5 c/kW.h with 100% diesel displacement, and assuming A-train LNG transportation is established and an AECO gas price of $4.5 per MMBtu).

3.1.2 Project Costs, Financing and Economics

The Project is to provide sufficient new gas-fired generation capacity between the end of 2014 and 2018 at Base Case forecast loads (a) to meet expected grid capacity planning requirements during these years with retirement of the two Mirrlees units[8], and (b) to displace during each of these years more than 95% of the expected grid diesel generation requirements (assuming long-term average hydro generation) and reduce overall diesel generation during drought years.

Table 3-1 provides a summary of the estimated Yukon Energy capital costs of $34.4 million (approximately $3.9 million per MW) for the initial Project facilities at the WTGS to be completed prior to the end of 2014, including the first two gas-fired units and other work related to LNG facilities (truck offloading, storage, and vapourization), distribution and communication line, utility trench, and decommissioning of the two Mirrlees diesel units. These costs are preliminary estimates developed in mid-2013 based on preliminary quotes and preliminary engineering.

Table 3-1: Estimated Capital Costs for Initial Project Facilities at WTGS (2013 $Millions)

Activity	Estimated Costs ($million)	% Total Costs
Planning Costs	2.4	7%
Engineering Services	1.5	4%
Project Management	1.0	3%
LNG Storage - EPC Contract	4.6	13%
LNG - Site Development	5.5	16%
LNG Gen - Engines	11.4	33%
Grid Connection	2.5	7%
Owners Costs - Construction Phase	3.7	11%
BOP - Preliminary Assessment	0.3	1%
BOP - Decommissioning[1]	1.4	4%
Total	**34.4**	**100%**

1. This work to decommission WD1 and WD2 ($1.45 million) is expected to occur in summer 2015; all other work is expected to be completed before the end of 2014.

An estimated capital cost of $4.4 million (2013$) has been provided for the third natural gas-fired unit, which is anticipated to be installed within a few years after the first two units are in service. Yukon Energy does not at this time have firm pricing for the third GE natural gas-fired generating unit - the $4.4 million estimate continues to be the best available information at this time.

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[8] Based on grid capacity planning criteria and the updated Base Case load forecast (see Appendix C, Table C-4), the minimum new grid capacity (cumulative to each date) required is 7.0 MW by 2015, 8.5 MW by 2016, 10.9 MW by 2017, and 13.0 MW by 2018. Based on the November 2013 Update to the 20-Year Resource Plan load forecasts (see Appendix C), the only potential requirement for new capacity in excess of these levels would occur in 2018 in the event of Scenario A2 (Base Case with Carmacks Copper and with Alexco).

The November 2013 update to Yukon Energy's 20-Year Resource Plan load forecasts (see Appendix C) indicates that 7.0 MW of additional grid capacity is required by 2015 at the latest for replacement of the two Mirrlees units at the WTGS that are to be retired in 2014 and 2015. As the thermal generation units at Whitehorse are expected to be relied upon on an increasing basis on the integrated grid, deferring replacement of these units would expose all grid customers to unreliable generation capacity as well as higher O&M costs related to higher fuel costs. The feasible and best diesel option to provide the required additional grid capacity would be to replace the retired diesel units with larger and more efficient new diesel units in order to secure fuel efficiencies during expected operation of diesel units to meet grid load requirements. However, this option would still require high cost diesel fuel-fired generation, which has greater environmental impacts and higher costs compared to the Project.

Capital costs associated with the installation of the gas-fired generation units at Whitehorse are incrementally higher than would be required with new diesel generation units, due primarily to the requirement to develop related LNG storage, vapourization and truck offloading facilities. However, lower fuel costs of LNG compared to diesel generation yield material net fuel cost savings each year with the Project compared to the new diesel generation alternative.

Figure 3-1 below indicates the extent to which net fuel cost savings with LNG are expected to exceed any added annual capital costs included in rates for the Project compared with the new diesel engine alternative[9].

- In 2015, the net ratepayer cost saving of $1.3 million is estimated, reflecting estimated annual capital and fuel cost for the Gas/LNG Project with its initial two units (8.8 MW) at $5.0 million being $1.3 million less that the estimated annual capital cost for the New Diesel option with its first unit (6.7 MW) at $6.3 million.

- In 2016, the net ratepayer cost saving of $2.2 million is estimated, reflecting estimated annual capital and fuel cost for the Gas/LNG Project with its initial two units (8.8 MW) at $6.0 million being $2.2 million less than the estimated annual capital cost for the New Diesel option with its two units installed by year end (13.4 MW) at $8.2 million.

- In 2017, the net ratepayer cost saving of $2.6 million is estimated, reflecting estimated annual capital and fuel cost for the Gas/LNG Project with its third unit assumed to be installed by year end (13.1 MW total installed) at $6.6 million being $2.6 million less that the estimated annual capital cost for the fully developed New Diesel option (13.4 MW) at $9.2 million.

- By 2018, the net ratepayer cost saving of $3.1 million is estimated after full development of both options.

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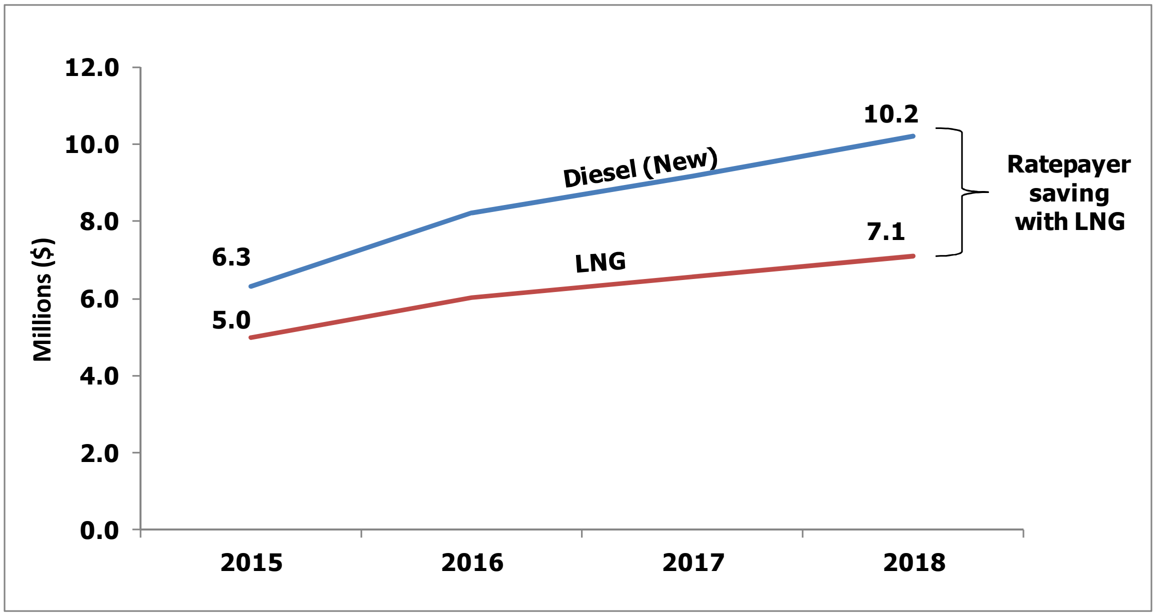
[9] See section 4.2 of the Application for details on these cost estimates. New diesel assumes 13.4 MW for two new units (one in 2014 and one in 2015), at a total capital cost of $33.6 million. LNG assumes 13.1 MW for three new units (two in 2014 and one in 2016), at a total capital cost of $34.4 million in 2014 and $4.4 million additional cost in 2016. All capital costs are assumed to be depreciated over 40 years, and an average return (debt and equity) on mid-year rate base is assumed at 5.45%/year (reflects YEC's approved 2012/2013 GRA). Fuel costs for each option are estimated based on forecast LTA diesel generation to supply the Base Case load forecast (see Appendix C - no Alexco): new diesel cost 24.6 c/kW.h; LNG cost 13.5 c/kW.h.

Figure 3-1: Annual Ratepayer Costs - LNG vs New Diesel: 2015-2018



Annual Ratepayer Cost for Capital & Fuel ($million per year)

	2015	2016	2017	2018
Diesel (New)	6.3	8.2	9.2	10.2
Gas/LNG	5.0	6.0	6.6	7.1
Saving (Diesel-LNG)	**1.3**	**2.2**	**2.6**	**3.1**

Yukon Energy has secured a minimum five-year (starting from date of first delivery) flexible LNG supply of up to 110,750 kg per day (approximately 250 m^3 per day) from Shell Canada's Jumping Pound production facility being developed near Calgary, which is planned to start operation before the end of 2014 with an estimated capacity of 250,000 metric tonnes per year (i.e., more than 1,500 m^3 per day). LNG costs to Yukon Energy under the contract with Shell Canada will fluctuate each month to reflect the latest published monthly Alberta Energy Company (AECO) index price of natural gas as reported by the Natural Gas Exchange[10].

Significant travel distances and the comparatively low density of LNG (approximately 60% of diesel fuel) emphasize the importance of having the most economical type of transportation possible while maintaining rigorous safety standards. Yukon Energy and Western Copper & Gold contracted PROLOG Canada to work with tractor trailer manufacturers to design a double trailer (A-Train) combination with a 95,000 litre capacity as an alternative to the Tridem units with a 54,000 litre capacity that are currently used to transport fuel into Yukon. The A-Train has been approved for use in Yukon for supply to Whitehorse along the Alaska Highway, but has yet to be approved for use in Alberta or British Columbia.

[10] There is also the potential in future to source LNG at any time (i.e., including during the term of the Shell Canada contract) from the Fort Nelson area in northern British Columbia should additional liquefaction facilities come into service in this area, and/or Shell Canada arranges to make LNG supplies available in this area, similar to how diesel suppliers currently store propane, diesel and gasoline at staged locations in the north (e.g., Whitehorse Marwell Industrial Subdivision).

The major advantage of the A-Train units over the Tridem units is the 76% higher net load capacity per trip.

- Assuming 40% energy conversion efficiency at a minimum for the modular gas-fired engines, the initial low volume LNG haul cost to Whitehorse from Shell's Calgary facility (2,325 km) is estimated at 4.4 cents/kWh with A-Train units and 6.3 cents/kWh with Tridem units.
- With development of more efficient operations with larger and more stable loads, the estimated A-Train delivery cost from Calgary is estimated to fall to 3.7 cents/kWh and from the much closer Fort Nelson area (978 km) the estimated cost would fall to 1.6 cents/kWh. The initial tractors for the LNG haul are assumed to be diesel-fueled engines. To secure lower costs and emissions, ongoing efforts will occur to secure LNG-fueled tractors as soon as they are available commercially in Canada.

Notwithstanding ongoing initiatives to secure the lowest practical cost for LNG delivery to YEC, the Project still provides material ratepayer cost savings even if Tridem units are used for LNG delivery. For example, even if Tridem units are assumed for LNG delivery with an AECO gas price at $4.5/MMBtu (i.e., well above recent AECO gas prices that approximated $3.5/MMBtu in November 2013), the delivered cost of Shell Canada-supplied LNG at Whitehorse would be less than 15.5 cents/kWh (assuming 40% minimum average fuel conversion efficient). At 15.5 cents/kW.h, LNG fuel cost would remain well below the cost of diesel fuel for Yukon Energy as approved in its 2012/2013 GRA of 28.7 cents/kWh in existing diesel units and 24.6 cents/kWh in potential new higher efficient diesel units.

3.2 ANTICIPATED TIMELINE

Yukon Energy is undertaking all required planning, environmental and socio-economic review and permitting, engineering design, procurement, contracting and other related activities to obtain authorizations and approvals necessary to allow construction of the Project to commence at the start of May 2014 to meet the in-service target of late 2014 for the first two natural gas-fired units. This schedule is driven by forecast thermal generation requirements for the winter of 2014/15, both to provide new thermal generation capacity for reliable service during that winter and to save in excess of $2.1 million of thermal fuel generation costs charged to ratepayers in 2015 (see Section 3.1.1).

In order to meet the target in-service date, initial long lead equipment (i.e., the gas-fired generators) was required to be ordered from a supplier selected and committed in Q2 2013; subsequently, other long-lead equipment (e.g., transformer, LNG storage tanks) is being ordered as required to protect schedule. The YESAB review process, completing the Part 3 Application process with the YUB, and any related permitting requirements are the key critical path elements currently affecting the required start of construction May 1, 2014 and subsequent Project in-service prior to the end of 2014[11].

[11] Decommissioning of the existing Mirrlees units is expected to occur in summer of 2015.

A more detailed review of key timeline elements is provided below:

- **Permitting and Approvals:** The schedule anticipates completion of the YESAB review, Part 3 YUB review, and Decision Body Approvals, and securing all needed permits and approvals required to commence construction of the Project by May 1, 2014. Section 6.1 contains a detailed list of all requested permits and authorizations for the Project.
    - **The YESAB Executive Committee assessment process** includes, at a minimum, the following major steps:
        - **A pre-screening adequacy review** – Yukon Energy filed a Project Proposal on August 6, 2013 and on November 1, 2013 YESAB concluded that the revised Project Proposal was adequate for YESAB to proceed with its screening.
        - **Screening with Public Comment** – Public comment on the revised Project Proposal is scheduled to conclude on December 20, 2014.
        - **Release of draft screening report** – February 1, 2014 is targeted for issuance of the draft screening report in order to meet the May 1, 2014 required start of construction.
        - **Public comment on the Draft Screening Report and release of the final report recommendations** – Based on experience with the Carmacks-Stewart Transmission Project and Mayo B Project reviews by YESAB, YEC's schedule assumes review and comment on the YESAB Draft Screening Report will be complete within 30 days of its release, with Final YESAB Recommendations provided within approximately 60 days of the YESAB's release of its Draft Screening Report, i.e., by April 1, 2014.
        - YEC's schedule assumes approval of the YESAB Recommendations by all Decision Bodies (i.e., the Yukon Government) within 15-20 days following release of YESAB's Recommendations.
    - **Part 3 review process by the YUB** as required for the Application is expected to involve a public hearing and issuance of the Board's report to the Minister by the end of March 2014.
    - **YG Permits and approvals** can be issued by territorial regulatory authorities only after release of the YESAB Final Report recommendations and only after each Decision Body has issued a Decision Document accepting the YESAB recommendations.
- **Project Construction** – The construction phase comprises a variety of tasks and activities, including site preparation, sourcing of required materials, construction of supporting infrastructure as well as primary facilities, management of fuel and hazardous waste, and the management of necessary work crews. Construction will be undertaken in accordance with the requirements of Part 3 of the *Gas Processing Plant Regulation*.
    - **Design, long-lead equipment orders, and contracting** – A contract for two gas-fired modular units was undertaken in June 2013 (includes engineering, shipping,

installation and commissioning of the units); it has been followed by a transformer tender; request for proposals ("RFP"s) and awards for project management and engineering services; an engineering, procurement, and construction ("EPC") tender for the LNG facilities (LNG storage, vapourization and truck unload); and a purchase order for three LNG storage tanks. The remaining construction-related contracts will be tendered as required in February/March 2014.

  - **Initial site preparation and civil works** – Starting May 1, 2014 (or as soon thereafter as permitting and/or weather allows), the Expanded Site Area will be prepared, e.g., land clearing, grubbing and grading for the construction footprint for the LNG facilities (including storage tanks), the modular gas-fired engine units, and all related facilities and site infrastructure (including the new substation).
  - **Installation of Equipment** – Engine module delivery is scheduled in the second half of July 2014 and LNG storage tank delivery is scheduled in the second half of September 2014. Subject to these deliveries, and as soon as site civil construction allows, installation of the GE modules and related facilities, the LNG facilities, the new substation and distribution line (with SCADA communications) will proceed (along with related mechanical and electrical contract work) with planned completion during October 2014. Initial LNG delivery for commissioning will occur at the end of these activities.
  - **Commissioning** – Commissioning is planned for each element of the Project as soon as feasible in October/November so that in-service operation can commence in the first half of December 2014 for the first two engine modules and the related LNG facilities. Commissioning work is likely to be done in segments based upon the construction schedule, and the need to have LNG facilities commissioned prior to start of engine module commissioning. Decommissioning of the WD1 and WD2 units is planned to occur in the summer of 2015, after the gas-fired engine modules are in-service.

- **Project Operation** – Operation of the facility pursuant to Part 4 of the *Gas Processing Plant Regulation* may only commence with approval of the Chief Operating Officer. An application for operation approval must include a report containing the results of pressure testing of the LNG facility, and the following manuals and programs with provisions as specified in Part 4 of the Regulation: an operating and maintenance manual, an emergency procedures manual, a staffing plan and a training program.
- **Delivery of LNG to Whitehorse**
  - Prior to proceeding with contracting for LNG fuel delivery from Shell Canada's facilities to the Whitehorse site as required for the Project, Yukon Energy is assessing opportunities for coordinating LNG shipping activity with NT Energy and other active and potential northern users of LNG, and YEC also plans an RFP for preliminary design and potential fabrication for the A-Train trailer units in order to address the tight timelines for the Project and the objective to keep delivered LNG costs as low as possible.
  - The A-Train has been approved for use in Yukon for supply to Whitehorse along the Alaska Highway, and applications are proceeding to secure approval for use as required

for the Project in Alberta and British Columbia. As noted in Section 3.1 of this Application, Tridem units are currently licensed and available to haul LNG in the event of delays in licensing or fabrication of the new A-Train units.

3.3 NEW OR EXPANDED PUBLIC WORKS DESCRIPTION

The Project does not require any new or expanded public works, undertakings or infrastructure.

3.4 SUMMARY OF ENVIRONMENTAL AND SOCIO-ECONOMIC IMPACTS

Chapter 7 of the August 2013 YESAB Project Proposal Submission provides a detailed explanation of the expected environmental and socio-economic impacts of the Project. In November 2013, the Project Proposal was revised based on modifications to the layout of the Expanded Site Area that resulted from ongoing engineering and planning efforts to define and secure lands required for the Project. These layout modifications did not change the overall conclusions regarding Yukon Energy's assessment of the potential environmental and socio-economic effects of the Project.

The Project is proposed to occur in Whitehorse within an existing environmental and socio-economic setting that has seen substantial commercial and industrial development and activities over a sustained period of time. Of particular note, dominant features of the existing conditions arise from the presence and influence of the existing Whitehorse Rapids Generating Station, the Whitehorse airport, the Schwatka Lake Aerodrome, Ear Lake Quarry, and nearby concrete and asphalt plants.

In summary, the Project, including mitigation measures set out in the Project proposal, is not expected to cause any likely significant adverse effect on the biophysical environment (e.g., vegetation diversity, wildlife diversity and habitat) or on the socio-economic components (e.g., recreation, human health, aesthetic quality, transportation, economy, and utility ratepayers). This conclusion reflects careful consideration of the Project design as well as the consideration of mitigation measures that reduce or eliminate potential adverse effects. Some residual effects are anticipated (e.g., the physical presence of the facilities result in an altered landscape and other changes for as long as the facilities are in place), but these are not expected to be significant given the developed and industrial nature of the immediate surroundings that have been persistent on the landscape for the last 55 years or more.

The Project will also have positive environmental and socio-economic effects in a variety of areas. Notably, the Project is expected to provide for reduced greenhouse gas and particulate emissions in the Project Study Area resulting from the displacement of diesel generation emissions. This is consistent with The Yukon Government *Climate Change Action Plan* and the *Energy Strategy for Yukon*. Both the plan and strategy set reduction of greenhouse gas emissions as a priority. Other positive effects include the potential for local jobs and business activity during the construction period (including opportunities for KDFN and TKC), savings for Yukon ratepayers compared to what would be required with continued reliance on diesel generation, and potential business and employment opportunities for KDFN and TKC.

The YESAB Project Proposal Submission (Chapter 7, Section 7.6) acknowledges that LNG has not previously been stored, nor natural gas used as a fuel, in Yukon. However, design, construction, operation and safety standards and regulations for LNG have been made increasingly stringent in North America over the last 40 years to prevent LNG accidents and minimize impacts should they occur. LNG facilities are also subject to numerous regulations to ensure health, safety and security of the environment and that the Canadian public are protected. LNG facilities must meet all standards, codes and regulations enforced by federal, provincial/ territorial or municipal jurisdictions (described in the YESAB Project Proposal Chapter 6, Section 6.6), including specific requirements set out in the Yukon *Gas Processing Plant Regulation*.

The Yukon context and experience with LNG is summarized in the recent YESAB Designated Office Evaluation Report on the Watson Lake Bi-Fuel Project[12]. The report ultimately concluded that the Watson Lake Project would "not result in significant adverse effects to health and safety that would necessitate the need for additional mitigation"[13] beyond that proposed by the proponent (specifically, application of non-discretionary legislation and standards and codes as listed in the Designated Office Evaluation Report, and implementation of the Proponent's commitments)[14].

The Project has the same regulatory context as the Watson Lake Project examined and recommended by the Watson Lake Designated Office. As such, the same non-discretionary legislation and standards and codes will apply to mitigate adverse effects on health and safety due to Project-related accidents and malfunctions[15]. YEC's use and reliance on the proposed Project facilities will be constrained by the terms and conditions of required permits, and requirements of relevant legislation that apply to the Project[16].

While the consequences of a fire, explosion or cryogenic burn may be high, the likelihood of such an event occurring with such consequences is considered to be extremely low. YEC's existing WTGS operations provide long-term experience addressing such risks related to use of diesel fuel at this site. YEC is required to have measures in place to address such events including an emergency response plan, an updated spills management plan and training for on-site workers and for drivers transporting LNG[17].

In summary, adverse effects on health and safety related to possible accidents and malfunctions with LNG and natural gas will be addressed through a comprehensive range of well established measures, including application of existing non-discretionary legislation, standards and codes, regulators' responsibility to ensure safety through regulation of the Project, and safety measures being applied by the proponent, including primary containment, secondary containment, safeguard systems and

[12] YESAB Project Number 2013-0009.

[13] YESAB Project Number 2013-0009 YESAB DO Report, page 37.

[14] YESAB Project Number 2013-0009 YESAB DO Report, page 60.

[15] Including the Occupational Health and Safety Act, the Occupational Health and Safety Regulations, the Occupational Health Regulations, the Environment Act, Spills Regulations and Storage Tank Regulations. Workplace Hazardous Materials Information System, as well as storage and handling requirements, will also be applied in compliance with the Transportation of Dangerous Goods Act to ensure workplace safety. Special waste regulations will be followed in accordance with the Environment Act. Yukon Energy will also adhere to appropriate LNG storage and transfer protocols such as CSA standard Z276-11 as well as applicable fire prevention codes, and will use equipment that meets or exceeds the safety and industry standards making a spill or unwanted ignition highly unlikely.

[16] Both CSA Z276-11 and the Yukon Gas Processing Plant Regulation prescribe strict requirements and standards related to licencing, construction of an LNG facility, operation and maintenance of an LNG facility, making physical and operational changes to an LNG facility, and records and reporting related to an LNG facility.

[17] Yukon Energy will work with a variety of regulatory bodies (including Yukon Mines and Resources and the Fire Marshall's Office) to ensure that health and safety measures meet regulatory requirements, including the requirements stipulated by CSA Z276 and the Yukon *Gas Processing Plant Regulation.*

separation distances. Based on these measures, the Project's adoption of a new fuel (LNG and natural gas) will be properly and prudently managed in the same way as current WTGS facilities properly and prudently manage operations with diesel fuel.

4.0 PROJECT JUSTIFICATION

The Project will provide reliable and flexible new generation capacity required today at Whitehorse to meet Yukon Energy's reserve capacity planning criteria[18] for the Yukon grid, including reserve capacity for seasonal low water periods and drought years while supplying short-term non-industrial load growth and peak winter demand. With conversion of generation from diesel to natural gas supplied by LNG, the Project will reduce Yukon Energy's forecast fuel costs, reduce forecast greenhouse gas and particulate emissions, and stimulate oil product-natural gas conversions in other sectors of the Yukon.

Whitehorse is the most appropriate location for initial changeover of diesel to natural gas using LNG. It is the nearest practical grid location for LNG deliveries from Alberta or British Columbia, and the location of the Yukon grid's largest load centre. It also offers the opportunity to use new gas fired generation to modernize the Whitehorse plant facilities, with its established infrastructure (including transformer capability and on-site staffing needed to operate and maintain the remaining diesel plant), concurrent with the retirement of existing diesel capacity at these facilities.

Justification for the Project is reviewed in detail below, addressing requirements as set out in OIC 2007/50:

- Yukon Grid Context & Changing Grid Load Conditions;
- Need for and Alternatives to the Project; and
- Risks and Potential Impacts on Ratepayers.

4.1 YUKON GRID CONTEXT & CHANGING GRID LOAD CONDITIONS

4.1.1 Yukon Grid Context - Relevance of Reliable & Flexible Thermal Generation

Although the isolated Yukon grid is predominantly served today by hydro-electric generation, reliable and flexible thermal generation continues to be a critical component. In 2012, 99% of the generation on the Yukon's Integrated Grid was from renewable sources such as hydro and wind.

As with other hydro-based systems in southern Canada, thermal generation is, and will continue to be, an integral and cost effective component required for reliable and flexible power generation on the Yukon grid. Unlike other hydro based systems in southern Canada, however, Yukon's isolated grid has no access to external North American power grids to secure extra power when it is needed, or to sell surplus renewable generation when it occurs. These features in Yukon enhance the ongoing requirement for reliable and flexible thermal generation on the Yukon grid.

[18] Capacity planning criteria adopted by Yukon Energy were reviewed by the Yukon Utilities Board in its review of Yukon Energy's 2006 20-Year Resource Plan, and consequently addressed in the recommendations from the YUB to the Minister of Justice dated January 15, 2007. Absent major new mine loads, the determinative requirement is that the grid be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"), i.e., assuming the loss of the system's single largest generating or transmission-related generation source (currently Aishihik generating capacity loss through failure of Aishihik-Whitehorse transmission).

Yukon Energy owns and operates 37 MW of reliable diesel generation, equal to 34% of YEC's firm winter grid capacity, to provide reserve capacity for the isolated Yukon grid in order to meet emergency back-up requirements, as well as grid loads during winter months and other periods when water availability for hydro generation is limited by seasonal or drought conditions or is otherwise insufficient to meet grid load requirements. Inability to rely on diesel generation in one or more of these circumstances would present an obvious and acute risk to human health and safety and public and private infrastructure, particularly during cold winter temperatures.

4.1.2 Changing Grid Load Conditions

When the Faro mine was operating in the 1990s, diesel generation operated throughout the year on the Whitehorse-Aishihik-Faro (WAF) grid. With the 1998 closure of the Faro mine and resulting decline in Yukon grid loads, there were no material requirements for these diesel generating units to operate on a routine basis. Consequently, retirement or refurbishment of diesel units was often deferred.

By the end of 2011, completion of the Carmacks-Stewart Transmission Project (CSTP) connected the WAF and Mayo-Dawson grids, and completion of the Mayo B Hydro Enhancement Project and the Aishihik Third Turbine expanded Yukon Energy's hydro generation capability on the new Integrated Grid with forecast reductions in long-term average diesel generation from these new projects estimated to be in excess of 20 GW.h per year in 2012 and 2013[19].

Notwithstanding these increased hydro generation capabilities, ongoing load growth on the Yukon grid has depleted the surplus hydro available since the 1998 Faro mine shutdown.

At the present time, thermal generation is once again becoming the default option to meet current energy and capacity requirements on the Yukon grid until long-term loads are sufficient to support economic new renewable generation. In response to these changed conditions, Yukon Energy was recently directed by the YUB (Board Order 2013-1, paragraph 60) for its 2012-2013 approved rate application to forecast hydro and diesel generation requirements assuming 100% long-term average hydro generation (rather than to forecast actual diesel generation for these years based on current water supplies).

As reviewed in Yukon Energy’s 2011 20-Year Resource Plan, Yukon Energy continues to pursue new renewable energy developments to displace growth in diesel generation requirements, and to implement a Demand Side Management (DSM) program to reduce load growth working with Yukon Electrical Company Limited (YECL).

Potential near-term hydro enhancement projects currently include Mayo Lake Enhanced Storage and Marsh Lake (Southern Lakes) Storage. For future consideration when long term loads can justify such developments, Yukon Energy is also pursuing a wind development that could range up to 20 MW at Techo (formerly Ferry Hill) in the Stewart Crossing area, as well as potential future hydro generation at

[19] See YEC 2012/13 General Rate Application (page 1-4 and 1-5) - reduction in long-term average diesel generation from these new projects forecast in 2012 at 23.9 GW.h and in 2013 at 26 GW.h (forecast grid generation loads at range of 416 to 430 GW.h/year).

various potential greenfield sites (including potential development of the West Creek hydro project near Skagway)[20].

As in the past, new thermal generation requirements on the grid will be reduced each time new renewable generation is developed in the future – however, in addition to providing conventional reliable and flexible grid backup generation capacity, thermal generation will continue to provide reliable energy supply on the Yukon grid until new renewable resource energy options are brought on line and used to displace energy that would otherwise need to be generated from fossil fuels.

4.1.3 Forecast Grid Diesel Energy Requirements without Major New Mines or New Sources of Generation

Yukon grid load growth over the planning period to 2030 without any major new mines or new sources of generation is projected to require electrical generation that exceeds the existing long-term hydro generation capabilities on the grid.

As summarized in Table 4-1 below (and detailed in Appendix C[21]), Yukon grid load growth under Base Case load conditions is projected to require average default diesel fuel energy generation (based on long-term average hydro and wind generation) that increases from 11 GWh in 2013 to 17 GWh in 2015, 41 GWh in 2020 and 92 GWh in 2030. This Base Case forecast, and the other grid load forecast scenarios in Appendix C which include Alexco and/or Carmacks Copper potential industrial loads, show expected default diesel generation requirements after load reductions from DSM programs - but prior to development of any new non-diesel generation supply capacity on the grid.

Table 4-1: Forecast Base Case (No Alexco) Grid Default Diesel Generation Requirement (2013-2030)

Year	2013	2015	2020	2025	2030
Default Diesel Generation[1]	11 GW.h	17 GW.h	41 GW.h	47 GW.h	92 GW.h

1. Default diesel requirement based on long-term average hydro and wind generation, prior to development of any new non-diesel generation supply capacity on the grid (beyond what is permitted in 2013).

The proposed Project will reduce these forecast default diesel generation requirements. As the requirement for default diesel generation increases, Yukon Energy will continue to assess the economics of developing additional renewable generation supply options such as hydro enhancements at Mayo Lake and Marsh Lake, wind projects, and greenfield renewable projects to reduce both diesel and LNG requirements wherever possible.

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[20] Yukon and Alaska recently signed an Economic Development Agreement with provision to look at the feasibility of transmission line connection between Skagway and the Yukon grid, including potential support for development of West Creek hydro.

[21] Appendix C provides YEC's November 2013 update to Appendix A to YEC's Overview of the 2011 20-year Resource Plan: 2011-2030.

Except during emergencies, drought or planned shutdowns, all of the forecast grid diesel generation in Table 4-1 would likely occur at the Whitehorse Diesel Plant[22].

The Overview of Yukon Energy's 2011 20-Year Resource Plan: 2011-2030 reviewed the variability in actual hydro and diesel generation on the grid between years, and within each year, due to variability in water availability, and how this highlights the need for reliable and flexible thermal generation to accommodate this variability.

Table C-3 and Figure C-2 in Appendix C provide a detailed review of potential variability in annual diesel generation for the Base Case load in the year 2016 under each of the 31 available water years of record from 1981 to 2011 (Figure C-2 shows the load duration curve for diesel for each load scenario). By way of example of the annual variability affecting grid diesel generation, the following are noted for 2016 diesel generation requirements with the Base Case load forecast (no Alexco)[23]:

- Long-term **average** diesel generation in 2016 for this load forecast is estimated at 22.9 GWh for 2016 based on all 31 water years. Board Order 2013-1 recently directed that approved revenue requirements used to set YEC's 2012 and 2013 rates in effect reflect long-term average diesel generation requirements relevant to load levels forecast for 2012 and 2013.
- The **median** year diesel generation forecast for the same load forecast based on all 31 water years is materially lower (at about 15.2 GWh) than the long term average, signifying the extent to which long term average diesel generation with the 2016 Base Case load (no Alexco) is driven by low water or drought conditions in a small portion of the water years.
- Actual diesel generation at any assumed load varies a great deal depending on the water conditions that occur (variances from long-term average hydro generation that affect YEC diesel generation costs in any year are accounted for through the Diesel Contingency Fund[24]):
    - In 16% of the 31 water years (i.e., five years, reflecting for this load scenario the worst drought conditions in five consecutive years from 1996-2000), diesel generation at the Base Case 2016 forecast load is estimated to range from 52.8 GWh to 101.4 GWh (i.e., 2 to more than 4 times the long term average at this load level).

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[22] See Appendix 5C to YEC's YESAB Project Proposal Submission for the Project (*Air Quality Assessment Update in Support of Permit renewal for Diesel Generator Operations,* SENES, 2011). Table 2.5 in this source shows that under forecast long-term average grid diesel generation then forecast for 2014 of 19.5 GW.h, all grid diesel generation is assumed to occur at the Whitehorse Diesel Plant.

[23] Review of other load scenarios and/or years in Appendix C show the extent to which annual generation variation linked to annual water variability changes with higher or lower grid loads. At lower loads, little if any actual diesel generation is likely in several water years - while at higher loads, material diesel generation is forecast for each of the water years (and the median and average long term diesel generation estimates come much closer together than occurs with the 2016 Base Case load with no Alexco). In all load cases, multi-year drought water conditions in the 1990s show that high diesel generation could be required for several years in a row.

[24] Variances [at GRA approved fuel prices] between actual diesel generation costs and expected diesel generation costs for each year (based on actual grid loads) are accounted for through the Diesel Contingency Fund (where funds are held in trust on behalf of ratepayers to help stabilize rates relative to cost variances caused by annual changes in hydro water flows). Variance in actual diesel fuel prices from approved GRA fuel prices are accounted for through Rider F provisions with charges or credits passed through to ratepayers based on actual energy use.

  - In contrast, in the five water years with the highest water availability (for this load scenario reflects 1981, 1983, 1991 and 1992, plus 1994), diesel generation at the Base Case 2016 forecast load is estimated to range from 0.3 GWh down to 0.1 GWh (i.e., only 1% to 0.4% of the long term average at this load level).

Forecast diesel generation also typically varies a great deal by seasons within the year, reflecting the combined effects in winter of higher grid loads and lower hydro generation. The long-term average forecast, for example, shows very low expected or long-term average diesel generation during about five months of the year (late May to late October) under each of the load scenarios. As with annual diesel generation variability, at any specific annual load level the seasonal diesel generation levels can also vary a great deal in any year depending on water availability.

One key implication resulting from seasonal and annual hydro generation variability is that overall thermal generation capacity on the Yukon grid will tend to show low average annual utilization, i.e., well below 80% to 90% average annual utilization that might be assumed in some baseload industrial operations. In addition, engine operation, as well as fuel purchases and deliveries related to Yukon Energy thermal generation, will show material annual as well as seasonal variability. A related implication is that the expected life of thermal generation facilities on the grid will tend to be materially longer than would be expected with higher levels of average annual use.

4.1.4 Forecast new Grid Capacity required without Major New Mines

Yukon Energy identified the need to replace or significantly refurbish its aging grid diesel generating units as part of its 2006 20-Year Resource Plan filing with the YUB. Ongoing load growth on the grid has resulted in increased use of diesel to meet peak demand and advanced the need to replace the units when retired with more efficient, reliable capacity.

Load growth on the grid combined with diesel unit retirements is now forecast to require material new installed generation capacity over the next 20 years (see Table 4-2 below[25]). A key factor is that all Yukon Energy diesel units, totalling 37 MW of capacity, are currently planned for retirement by 2031. Moreover, these diesel retirements may need to be advanced as usage of the engines increase or parts and maintenance costs increase or become unavailable.

In Whitehorse, the WTGS was initially commissioned in 1968, and has seven diesel engines with an installed nameplate capacity of 25 MW that are all planned to be retired within the next 13 years (9 MW retired by 2015) as follows:

- In 2014/15, two Mirrlees (WD1 and WD2) are planned for retirement, removing 9 MW of nameplate capacity from this plant and from the grid.

[25] Capacity planning criteria adopted by Yukon Energy were reviewed by the Yukon Utilities Board in its review of Yukon Energy's 2006 20-Year Resource Plan, and consequently addressed in the recommendations from the YUB to the Minister of Justice dated January 15, 2007. Absent major new mine loads, the determinative requirement is that the grid be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"), i.e., assuming the loss of the system's single largest generating or transmission-related generation source (currently Aishihik generating capacity).

- By 2025, the remaining Mirrlees unit (WD3 in 2021) and the three EMDs (2025) are planned for retirement, removing an additional 13 MW of nameplate capacity; the final CAT unit (WD7) at the Whitehorse plant is planned for retirement in 2026. These retirements may also be advanced if Yukon Energy faces issues with spare parts, repairs or other considerations that short a unit's effective life.

When the Mirrlees units (the oldest installed diesel units) were evaluated, WD3 was deemed to be in the best condition and was refurbished in 2010. WD1 and WD2 (both first in service in 1968) are currently scheduled for retirement in 2014 and 2015, respectively.

Table 4-2: Forecast Base Case (No Alexco) New Grid Capacity Requirement (2015-2030)

Year	2015	2020	2025	2030
Forecast Non-Industrial Peak[1]	76.5 MW	83.9 MW	93.3 MW	105.5 MW
Reliable Capacity Required[2]	113.5 MW	120.9 MW	130.3 MW	142.5 MW
Existing Peak Winter Capacity[3]	106.5 MW	100.2 MW	84.7 MW	78.9 MW
New Capacity Requirement[4]	7.0 MW	20.7 MW	45.6 MW	63.6 MW

1. Non-industrial peak load on grid, after assumed Demand Side Management (DSM), less 1 MW for assumed Haines Junction load. See Appendix C.
2. Capacity planning requirements with N-1 reserve capacity (Forecast Non-Industrial Peak plus 37 MW for Aishihik hydro generation capacity [N-1 event is loss of transmission to the Aishihik hydro generation - also means loss of Haines Junction diesel capacity]).
3. Existing winter capacity in 2013 is 114.49 MW excluding Fish Lake hydro and Haines Junction diesel (see Table 2-3, Yukon Energy 20-Year Resource Plan: 2011-2030, December 2011). Reductions after 2013 reflect planned retirements of diesel engine units and the de-rated capacities of these units at this time (e.g., Mirrlees WD1 and WD2 have de-rated capacity of 8 MW versus rated capacity of 9.07 MW).
4. New capacity requirement equals forecast peak with N-1 reserve less existing peak winter capacity.

In summary, Whitehorse diesel generation capacity to be retired in 2014/2015 and ongoing non-industrial load growth result in a requirement for at least 7.0 MW of new generation capacity on the grid by late 2014, 8.5 MW by late 2015, 10.9 MW by late 2016, and 13.0 MW by late 2017 to maintain grid system capacity needed for forecast non-industrial peak winter loads. Subject to any new capacity provided by new renewable generation[26], these forecasts confirm the additional new thermal generation capacity that is expected to be needed on the grid each year after 2017 to meet capacity planning requirements.

[26] Mayo Lake Enhanced Storage would not provide any new firm capacity to the grid. Marsh Lake (Southern Lakes) Storage might potentially provide 1 MW of added winter grid capacity.

4.2 NEED FOR AND ALTERNATIVES TO THE PROJECT

The Project responds to the current need for 13 MW of reliable and flexible new grid generation capacity at Whitehorse. As reviewed in Section 4.1.4, new grid generation capacity is required by 2015 (7 MW) in response to the scheduled retirement in 2014 and 2015 of two end-of-life and to-be-retired Mirrlees diesel units at the WTGS, and ongoing non-industrial load growth on the grid (Base Case with no Alexco) results in this new grid generation capacity requirement expanding to 13 MW by 2017. These new generation capacity requirements on the isolated Yukon grid are forecast after full consideration of DSM initiatives by YEC and YECL to reduce ongoing grid load growth.

As reviewed below, the status quo and renewable resources are not feasible alternatives today to the Project and comparison with available diesel generation options confirms that the Project is the least cost alternative available for Yukon Energy to supply this new grid generation capacity that is needed beginning in late 2014 on the Yukon grid.

4.2.1 Status Quo is not a Feasible Alternative

Under a "status quo" or "do nothing" alternative, Yukon Energy would not retire the existing WD1 and WD2 Mirrlees diesel units as scheduled in 2014 and 2015.

However, retention of the WD1 and WD2 Mirrlees units beyond planned retirement would expose all grid customers to unreliable generation capacity as well as higher O&M fuel costs, and replacement or life extension of these units would be required in any event as soon as feasible, i.e., by late 2015 at the latest.

In summary, the "status quo" option is concluded to not be a feasible alternative today. Exposure of grid customers to unreliable generation that fails to meet the grid reserve capacity planning criteria, as would occur with this option, is not acceptable to Yukon Energy.

4.2.2 No Feasible Renewable Resource Alternatives to the Project

No feasible renewable resource alternatives to the Project have been identified within the relevant time period.

Yukon Energy's 2011 Resource Plan examined a wide range of near-term resource supply options[27], none of which (other than new diesel engines) is a viable alternative today to the Project.

- Of the near-term supply options, LNG was the only option with the capability to meet all of the forecast Yukon grid load scenarios in Yukon Energy's 2011 Resource Plan (these scenarios included Victoria Gold, with loads considerably higher than those included in the November 2013 update in Appendix C) without requiring significant diesel generation, and was also the only option (other than diesel) to rank high on both reliability and flexibility (which are key

[27] See Chapters 6 and 8, Yukon Energy Corporation; *Overview of 20-Year Resource Plan: 2011-2030*; July 2012.

requirements related to the near term generation capacity needs being addressed by the Project).

- Excluding the relatively small energy supply impact of potentially available near-term hydro enhancement projects[28], LNG was also identified as the lowest cost near-term resource supply option (ranked medium/high in affordability).
- Potentially available near-term hydro enhancement projects would not materially affect grid requirements for new generation capacity in 2015 and subsequent years[29].
- At forecast grid loads in Yukon Energy's 2011 Resource Plan, none of the non-hydro renewable resource options (e.g., wind and biomass were both examined) could provide levelized costs of energy over their life competitive with diesel generation[30].

4.2.3 Diesel Generation Alternatives to the Project

Two diesel generation alternatives to the Project during the 2014-2017 period have been considered: (a) life extension of the Mirrlees units (WD1 and WD2) and (b) replacement of the Mirrlees units with new higher-efficiency diesel engines[31].

Overall, after looking at the relevant costs and risks, it is concluded that the only practical and cost effective option today to the Project is the new higher efficiency diesel replacement option. Accordingly, the new higher efficiency diesel replacement option has been selected as the relevant "feasible and best alternative" to the Project.

Each of the two diesel generation options that were examined is reviewed in more detail below:

1. **Life Extension of WD1 and WD2 Units:** Yukon Energy's 2006 20-Year Resource Plan proposed life extension expenditures for the four Mirrlees units on the grid (included FD1 at Faro)

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[28] Potential near term hydro enhancements include Mayo Lake Enhanced Storage Project and Marsh Lake Storage. These two options are estimated respectively to supply 4 and 6 GW.h/year (long-term average) incremental energy supply to the grid. Development of the two options, if and when regulatory requirements can be satisfied, would still leave material forecast long-term average diesel generation requirements (see Appendix C to this Application; reviews long-term average diesel requirements forecast with Base Case loads [and no new non-diesel generation] at 17 GW.h/yr in 2015, increasing to 41 GW.h by 2020). For future consideration when higher long-term grid loads can justify such developments, Yukon Energy is also pursuing a 20 MW wind farm at Techo (also known as Ferry Hill) in the Stewart Crossing area as well as potential future hydro generation at various potential greenfield sites; however, before and after such future new renewable energy developments, thermal generation will continue to provide reliable supply on the Yukon grid during the period between successive new renewable resource developments.

[29] Mayo Lake Enhanced Storage Project would not provide any new firm winter capacity to the grid. Marsh Lake (Southern Lakes) Storage might potentially provide 1 MW of added firm winter grid capacity.

[30] See Yukon Energy: *Overview of 2011 Resource Plan: 2011-2030*, including Table 8-2, which reviews wind and biomass options in the context of much higher near-term loads.

[31] YECL proposed, in its recent GRA, a 2 MW new diesel engine on the grid at Carcross at a cost of $3 million. The sole purpose of this project, if developed, is to provide back-up for Carcross and Tagish area customers in the event of loss of power from the grid, i.e., the YECL project is not an alternative to the need for YEC to replace retired thermal capacity at Whitehorse. Costs of this YECL project have yet to be approved by the YUB to be recovered in rates. Given the earliest timing for this project (2015) and its small size, its development (if approved by the YUB) will not affect the required timing or feasibility of the Project's initial 8.8 MW development with two gas modules in-service by late 2014 - at most, the YECL project might affect timing of the Project's third unit if actual peak load requirements on the grid by late 2016 are less than forecast in Appendix C of this Application.

as a low capital cost option to meet near-term grid reserve capacity requirements in response to the scheduled retirement of these units at a time when no material diesel generation was expected on the grid due to the surplus hydro generation conditions then prevailing. Subsequently, overhauls were completed for FD1 and WD3.

The current situation differs from that reviewed earlier in many respects, including current forecasts for grid diesel generation as well as updated assessments of the practicality and cost requirements for this option. In summary, the following implications are noted for the Mirrlees life extension alternative:

a. Based on the Corporation's recent experience with refurbishment and subsequent maintenance of the WD3 Mirrlees in Whitehorse and FD1 Mirrlees in Faro, the following have been concluded:

    i. Refurbishment of the remaining two Mirrlees units at WTGS (WD1 and WD2) is not considered to be practical or cost effective due to increasing lack of parts for these 45 year old engines.

    ii. The Corporation will be able to utilize some of the parts off of the retiring WD1 and WD2 engines to keep the two refurbished units operating prior to currently planned retirement dates.

    iii. If parts were not an issue, updated cost assessment for balance of plant work requirements for the WTGS suggest that extending the 9 MW rated capacity of these two units for another 10 years would likely require a capital cost of at least $6.75 million[32] with risks that actual capital costs would exceed this amount.

b. Even if feasible and cost effective, the life extension option for WD1 and WD2 would at most only provide 9 MW of the forecast new capacity requirement and would do this at most for only 10 years, i.e., additional new capacity would be required by late 2016, with at least 4 MW of added capacity needed by late 2017 (to meet capacity requirements in early 2018) and the full 9 MW of new capacity would once again be needed by at least late 2024. The location and costs for this added 4 MW and subsequent 9 MW of capacity would need to be addressed.

c. Expected grid diesel generation requirements would be supplied during this period by relying on other existing diesel units (i.e., WD1 and WD2 use would likely be avoided, other than for emergency) at an approved average fuel cost of 28.7 cents/kW.h[33], e.g., $4.9 million fuel cost for forecast 2015 Base Case grid loads of 17 GW.h, and

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[32] Assumed capital cost of at least $0.75 million per MW or 50% of the minimum $1.5 million per MW likely for a new unit in an existing facility without extensive balance of plant cost requirements such as are expected to be required at WTGS today. Based on experience, costs today for WD1 and WD2 are expected to materially exceed Yukon Energy's 2008/2009 GRA filing estimates of an expected average cost per MW for Mirrlees unit life extension at Whitehorse of approximately $0.482 million/ MW including provision for common upgrade costs required.

[33] YUB approved YEC 2012/2013 GRA forecast cost of grid diesel generation for YEC average at 28.7 cents/kWh; includes approved forecast diesel fuel price at Whitehorse at $1.0513/ litre (higher prices at other grid generation sites). Average fuel costs for diesel generation on the grid reflect forecast average efficiencies of existing units expected to be used.

approximately 700 tonnes or more of GHG emissions from Yukon Energy's facilities per GW.h of diesel electricity generated.

2. **New Higher-Efficiency Diesel Engine Replacement:** Given the Base Case forecasts for diesel generation requirements, under this option Yukon Energy would secure higher efficiency new diesel engines. Based on planning assessments, the best option in this regard today would likely be to install new diesel engines within the existing Whitehorse diesel plant, utilizing the engine bays previously used by the two retired Mirrlees units[34].

   For comparative purposes, an alternative has been examined assuming two new 6.7 MW diesel engines (13.4 MW)[35], with the first unit installed in late 2014[36] at an estimated capital cost of $22.5 million (this unit will not fully meet the 7.0 MW required new capacity for early 2015 under Base Case loads) and the second unit installed in late 2015 at an estimated capital cost of $11.0 million[37] (the combined 13.4 MW of new capacity will meet required new capacity forecast through 2018 under Base Case loads). It is further assumed that these new units have higher fuel efficiency than the current units that results in lower average fuel costs of 24.6 cents/kW.h (for generation from the new Whitehorse units) at currently approved fuel prices[38]. Implications of this option include:

   a. Installation of these two new diesel units would address two of the stated objectives for the Project:

      i. Provide the required new capacity needed for reliable grid electricity supply (annual costs for depreciation and return on the $33.6 million capital cost would approximate $2.0 million in 2015 [first unit in service] and $2.6 million in 2016[39] [two units in service]); and

[34] Investigations to date have not revealed a viable modular diesel engine option that would be located outside the current diesel plant and suited to Yukon Energy needs, i.e., the specific modular option available for natural gas engines in a northern climate is not available for diesel engines at this time, and other modular options identified to date are too small for Yukon Energy's needs.

[35] Yukon Energy completed preliminary engineering and costing in 2013 for a dual-fuel (gas-diesel) engine option that would have utilized these two Mirrlees bays with two new 6.7 MW Wartsila dual fuel engines. Cost estimates for balance of plant upgrade work required for this option has been utilized for assessing the likely capital cost required for two new 6.7 MW diesel units located in these same bays within the existing Yukon Energy diesel plant. In utilizing these bays for a new higher efficiency option, it is reasonable to focus on new units that would effectively utilize the available space (leads to larger units, for example, than Yukon Energy is selecting for modular gas engines with no similar constraints or that would be used by Yukon Energy to replace the EMD units in the smaller EMD bays at the existing diesel plant).

[36] Although this timing was feasible when the option was examined in 2012 and early 2013, it is clearly not feasible today, i.e., in practice, the earliest that a new diesel could be installed today would be for late 2015.

[37] Estimate includes planning costs, required balance of plant upgrade work inside the existing diesel plant, and demolition costs to remove WD1 and WD2. Overall capital cost of $33.6 million for 13.4 MW new capacity averages $2.5 million per MW, and is competitive with estimated greenfield site cost for new generation excluding costs for related transformation. Upgrading the existing old diesel plant would extend the life of this facility and avoid the need for added transformation and other costs associated with developing a new greenfield facility.

[38] Assumes 40% efficiency (4.28 kW.h/litre) and current YUB approved GRA (2012/2013) diesel fuel prices for Yukon Energy at Whitehorse ($1.0513 per litre).

[39] Assumes 40 year depreciation and average return cost (debt and equity) of 5.45%/year, based on average return on equity (40% at 8.25%) and average cost of new debt (60% at 3.6%) for 2013 as approved by YUB for Yukon Energy's 2012/2013 GRA.

ii. Facilitate use of more efficient diesel generation units to meet a substantive share of ongoing grid diesel generation requirements (e.g., assume meet approximately 90% of the long-term average 2015 diesel generation with the first new unit, increasing to 100% in 2016 with the second new unit[40]), with resulting annual fuel cost savings relative to existing diesel approximating $0.6 million in 2015 and $0.9 million in 2016).

b. Utilizing the existing Mirrlees bays for new units creates schedule risks with the need to retain existing units in service until at least March, and then to remove the existing unit and install the new one prior to December of the same year.

c. Opportunities to reduce diesel generation emissions would be deferred, and economic development opportunities that could be realized from the Project related to introducing lower cost natural gas fuel to Yukon would also be deferred.

4.2.4 Project Economics - Ratepayer Cost Savings Compared to New Diesel Alternative

Concurrent with the modernization and diesel unit replacement needs today at the Whitehorse Diesel Plant, there is an opportunity to convert from diesel to LNG-supplied gas-fired generation to meet growing electricity loads on the Yukon grid with a fuel that is cleaner burning and cheaper than diesel, benefiting both the environment and Yukon ratepayers.

The existing WTGS operation is an optimum location today to pursue YEC conversion of generation from diesel to natural gas. Whitehorse is the nearest practical grid location for LNG deliveries from Alberta or British Columbia. It is also the location of the Yukon grid's largest load centre. Finally, the WTGS offers the opportunity to use new gas fired generation to modernize the Whitehorse plant facilities, with its established infrastructure (including transformer capability and on site staffing needed to operate and maintain the remaining diesel plant), concurrent with the retirement of existing diesel capacity at these facilities[41].

The specific near-term opportunity at the WTGS relates to the retirement of WD1 and WD2 diesel units (9.1 MW of rated capacity) in 2014 and 2015, combined with the requirement for at least 7.0 MW of new grid generation capacity by late 2014 and 13 MW by late 2017.

The GE pre-engineered J624 modular unit[42] being acquired for the Project is an ideal scale for the initial conversion Project, i.e., two of these units (approximately 8.8 MW total new engine capacity) would accommodate initial minimum new capacity requirements for 2015 and a third unit (approximately 13.1

[40] Percent displacement of other diesel estimates based on analysis provided in Appendix D. Actual displacement likely to be less than these estimates given the assumptions adopted in Appendix D to assess maximum potential displacement with full utilization of the new capacity.

[41] The option of developing a new greenfield site for the Project in the Whitehorse area and separate from the WTGS was considered but was not found to be cost effective or practical. Major elements of the existing diesel plant at the WTGS will continue to be required over at least the next decade under any scenario examined. As noted, the WTGS also provides established infrastructure that facilitates cost effective development of the Project.

[42] Review of potentially available modular unit options indicated that GE is the only vendor currently offering such gas fired options in the scale relevant to Yukon Energy and with demonstrated cold climate northern operating experience.

MW total new engine capacity) would meet expected near-term new capacity requirements for 2017 or later. Accordingly, the natural gas Project has been defined to provide 13.1 MW of new capacity with two units (8.75 MW) in service by late 2014 and the third unit (4.375 MW) in-service as soon as required thereafter (assumed for analysis to be in service by late 2016 given the Base Case new capacity requirement forecast).

Table 4-3 compares, for the 13.1 MW gas-fired Project and the 13.4 MW new higher efficiency diesel generation alternative at the WTGS, estimated capital costs as well as forecast near-term (2015 to 2018) annual capital and fuel costs to ratepayers[43]. As summarized earlier in Figure 3-1, Table 4-3 indicates that the annual fuel cost savings with the Project's gas-fired generation are far in excess of any added annual capital costs included in rates for the Project compared with the new diesel engine alternative.

In summary, as reviewed in Table 4-3, the Project as defined will provide sufficient new gas-fired generation capacity between the end of 2014 and 2018 at Base Case forecast loads (a) to meet grid capacity requirements during these years with retirement of the two Mirrlees units, and (b) to displace during each of these years 95% or more of expected grid diesel generation requirements (assuming long-term average hydro generation), with related reductions in required diesel generation needed during extreme drought years.

Capital and fuel cost comparisons in Table 4-3 for the Project and the new diesel alternative are each reviewed in more detail below.

Capital Costs

Looking only at the capital cost requirements, replacing the old diesel units with new and more efficient diesel units would have incrementally lower capital costs compared to replacing the old diesel units with new gas-fired generating units. The main source of the added capital costs for the Project compared with new diesel is to establish the new facilities needed for LNG truck unload, storage and vapourization.

As shown in Table 4-3, forecast annual capital depreciation and return costs are lower each year for the new diesel alternative compared to the Project (i.e., $0.6 million lower in 2015, a $0.2 million lower in 2016 and $0.4 million lower in each of 2017 and 2018).

[43] Project capital cost estimates as shown in Table 4-3 are as described in Section 3.1.2 of the Application for the Project, and as described in Section 4.2.3 of the Application for the new diesel option. Fuel costs for each option, as well as annual capital costs, are estimates as described in Table 4-3 (fuel costs as estimated are all fuel costs required to supply the forecast Base Case thermal generation in each year as per Appendix C - see also Section 3.1.2 of the Application for review of LNG haul cost options and costs). Non-fuel O&M costs are assumed to be the same for both options and are not included in the analysis. Table 4-3 assumes that when a new facility is installed late in a year, no depreciation is charged in that year and no generation occurs in that year; in addition, it is assumed that no return is charged in 2014 for either option.

The following are noted with regard to the comparative capital costs for these options:

- Assuming that the first new diesel unit could be installed by the end of 2014 (on an equivalent schedule to the Project), over 85% of the new annual capital costs associated with the Project by late 2016 would be required in any event with the new diesel option in order to provide required capacity for the integrated grid[44].
- The Project, in contrast to the new diesel engine option located within the WTGS, includes all new facilities, new transformation, and the establishment of LNG unload, storage and vapourization infrastructure in Whitehorse.
- The Project with three separate units (rather than two units for similar overall new diesel capacity) offers greater flexibility than the new diesel engine option for efficient operation in response to changing grid load conditions.

Annual Fuel Costs

Considering the near-term Base Case grid thermal generation forecasts provided in Appendix C, the Project's gas-fired generating units would have materially lower annual fuel costs compared to the new diesel option.

Fuel cost savings with LNG compared to new diesel generation are estimated in Table 4-3 at 11.1 cents/kWh, assuming gas-fired engine fuel costs at 13.5 cents/kWh and new higher efficiency diesel engine fuel costs at 24.6 cents/kWh.

- Gas-fired engine fuel costs assume engine efficiency at 40%[45], and LNG supply from Shell Canada at Calgary (per Yukon Energy's contract with Shell and an assumed AECO gas price of $4.5 per MMBtu) using diesel powered A-Train trailers.
- Diesel engine fuel costs assume engine efficiency at 40% (4.28 kWh/litre) and current YUB approved YEC 2013 GRA diesel fuel prices at Whitehorse ($1.0513/litre).

The annual fuel cost estimates in Table 4-3 assume long-term average thermal generation requirements are supplied with the new and more efficient gas or diesel generation units being operated on a prioritized basis where feasible to maximum capacity prior to use of any other grid diesel generation. The annual fuel costs estimates in Table 4-3 also assume operation of these new units to enhance hydro storage for use in wintertime (so that enhanced hydro generation can help to displace diesel generation during periods of peak diesel requirements).

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[44] Capital cost estimates for the Project of $34.4 million to end of 2014 (for 8.75 MW) with an additional $4.4 million estimated for the third engine (4.375 MW) assumed in late 2016 in Table 4-3, include planning costs, new LNG unload, storage and vapourization infrastructure, new transformer capacity and demolition costs to remove WD1 and WD2. Capital cost estimates for new diesel generation of $22.5 million to end of 2014 (6.7 MW), and an additional $11.1 million estimated for the second engine (additional 6.7 MW) in 2015 include all required balance of plant work and demolition costs to remove WD1 and WD2.

[45] GE specifications for the new gas-fired units provide for higher conversion efficiency than 40%, and this is assumed to reflect conservative operating assumptions. For consistency, the same 40% efficiency in operation is assumed for new higher efficiency diesel engines.

The following examples help to explain the issues related to assumed operation of new units:

- The 2016 Base Case thermal generation long-term average requirement of 22.9 GW.h in fact reflects widely varying thermal generation over 31 different possible water years of record (see Table C-3 of Appendix C), e.g., during the four worst drought years the annual thermal generation requirement to supply the 2016 Base Case load ranges from 63.1 GWh to 101.4 GW.h.
- 7 MW of new gas-fired generation could provide about 56 GW.h per year at 91% annual average utilization, and the annual capability to displace "old" diesel generation would be further curtailed in practice when the grid thermal generation requirement is focused only in winter months.
- Operation of the new gas-fired generation capacity can be used, however, to assist in storing water at Aishihik and (to a much lesser extent) at Mayo during summer or other periods when thermal generation requirements are low, thereby allowing added hydro generation capability to be utilized in peak winter months – and in this manner, low cost gas-fired generation can in effect displace additional "old" diesel generation that would otherwise be required.

To assess potential "old" diesel generation displacement with new gas units, the impact of one MW increments of gas-fired generation (within relevant ranges) have been examined with the YECSIM model[46] for the grid system assuming maximum operation of the units through the year (see Appendix D, Table D-1 for 2015 and Table D-2 for 2016 and 2017):

- As reviewed in Appendix D, YECSIM analysis of the 31 water years with the current grid generation and permits indicates that installing only 7.0 MW of new gas-fired generation in 2015 (i.e., minimum new capacity requirement in that year) would likely not displace more than about 90% of Base Case long-term average diesel generation required for 2015 (and less in 2016 and subsequent years), even if operated year round so as to maximize hydro storage, given the inability of this scale of generation to address thermal generation requirements during the most severe drought years[47]. Similarly, installing 8.5 MW gas-fired generation in 2016 would likely not displace more than about 93% of expected diesel generation (see Table D-2 of Appendix D).
- To displace more than about 95% of expected diesel generation (at long-term average hydro conditions) with gas fired generation operated in this assumed manner with Base Case loads, the YECSIM analysis indicates that 8 MW of gas-fired generation is required by 2015, 9 MW by 2016, and 10 MW in 2017 (see Tables D-1 and D-2 of Appendix D). In each of these cases, diesel generation exceeds 5 GW.h/year in only one extreme drought water year.

[46] "YECSIM" is the generation simulation model for the Integrated Grid developed for YEC by KGS Group.
[47] See Appendix D, Table D-1. Column F shows that 5 MW of gas fired generation operated at full capacity with Base Case loads displaces only 75% of expected [long-term average] diesel, while 6 MW displaces 85% of expected diesel and 7 MW displaces 91%. Columns I to M show the extent to which expected diesel during the worst drought years is impacted by each MW of added gas-fired generation, e.g., with 6 MW gas generation in 2015 there are still three drought water years [1997 and 1999 shown in table] with diesel generation greater than 5 GWh, while with 7 MW gas generation in 2015 there is only one drought water year [1999] with diesel generation greater than 5 GWh. Table D-2 shows that, due to load growth with Base Case loads, expected diesel displacement for each of these gas-fired generation capacities is reduced in 2016 and 2017, e.g., 7 MW new capacity displaces only 86% of expected diesel in 2016 and 81% of expected diesel in 2017.

- To displace over 99% of expected diesel generation with Base Case loads, the YECSIM analysis indicates that 9 MW of gas fired generation is required by 2015, and 11 MW by 2016 (as well as 2017). In order to secure similar diesel displacement without requiring incremental new generation, Yukon Energy is also examining (for a future stage of the Project) retrofit of the remaining EMD units at Whitehorse to a blended use of gas and diesel during the few times when new gas-fired engines would not be fully able to displace all diesel generation.

Based on the Appendix D analysis as reviewed above, Table 4-3 assumes that the 8.8 MW gas-fired generation will displace 100% of Base Case long-term average diesel requirements in 2015 and 95% of these requirements in 2016; similarly, Table 4-3 assumes that the 13.1 MW gas-fired generation available by 2017 will displace 100% of Base Case long-term average diesel requirements in 2017 and 2018[48].

Net Ratepayer Cost Savings

Overall, the annual net savings available to Yukon ratepayers from the Project (including both fuel and capital cost impacts) relative to the new diesel alternative are estimated with Base Case load in Table 4-3 at $1.3 million in the first full year of operation (2015), increasing each year thereafter as forecast thermal generation requirements increase, e.g., to $2.2 million in 2016, $2.6 million in 2017 and $3.1 million in 2018. The cost savings to Yukon ratepayers from the Project will continue throughout the life of the Project, subject to annual grid thermal generation requirements remaining at levels reflected in Table 4-3. These cost savings will increase as load and requirements for thermal generation increase in future, or with other load scenarios examined in Appendix C (e.g., reopening of Alexco mine and/or connection of Carmacks Copper mine).

Assuming that the YUB adjusts rates for this period as required to reflect changing conditions, these savings relative to the new diesel alternative at forecast loads will flow through to utility ratepayers throughout Yukon. Related ratepayer benefits would occur in reducing severe cost impacts associated with major drought conditions and in allowing for much lower incremental fuel costs that are much closer than diesel fuel costs to current run-out rates reflected in existing retail rate schedules.

[48] Similar analysis was used to support the assumed new diesel generation displacement of other diesel as shown for each year in Table 4-3 (90% displacement with 6.7 MW capacity in 2013, and 100% displacement with 13.4 MW capacity in 2016 through 2018).

Table 4-3: Ratepayer Impacts from Whitehorse Diesel-Natural Gas Conversion Project ($million) (Project compared to New Diesel Alternative)

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	22.55	11.1			
	LNG	34.36		4.4		
Net	Diesel (new)	22.55	33.1	32.3	31.5	30.7
	LNG	34.36	33.5	37.1	36.2	35.2
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.527	0.805	0.805	0.805
	LNG		0.823	0.823	0.933	0.933
Return	Diesel (new)		1.517	1.783	1.739	1.695
	LNG		1.850	1.925	1.997	1.946
Total	Diesel (new)		2.044	2.588	2.544	2.500
	LNG		2.673	2.748	2.930	2.879
Difference (LNG-Diesel)			**0.629**	**0.160**	**0.386**	**0.379**
Annual Fuel Cost ($million)						
Forecast Diesel (GWh)			17	22.9	26.9	31.4
% New	Diesel (new)		90%	100%	100%	100%
	LNG		100%	95%	100%	100%
Fuel Cost	Diesel (new)		4.252	5.633	6.617	7.724
	LNG		2.295	3.266	3.632	4.239
Difference (LNG-Diesel)			**-1.957**	**-2.368**	**-2.986**	**-3.485**
Net Ratepayer Impact (S million)						
	Diesel (new)		6.296	8.221	9.161	10.225
	LNG		4.968	6.014	6.562	7.118
Difference (LNG-Diesel)			**-1.328**	**-2.208**	**-2.600**	**-3.106**

Notes:

1. All capital costs depreciated over 40 years; return on mid-year rate base at 5.45%/year.
2. Diesel fuel costs at 24.6 c/kWh new diesel, 28.7 c/kWh other diesel.
3. LNG delivered fuel costs at 13.5 c/kWh (assumes supply from Shell Canada at Calgary at an AECO gas price of $4.50 per MMBtu and using A-Train units for delivery to Whitehorse).

In summary, based on review of the above investigations and analysis, it is concluded that the specified need to meet near term forecast requirements for reliable and flexible new capacity on the Yukon grid would best be met through development of the Project. Compared to the feasible and best alternative available today (i.e., new higher efficiency diesel replacement), at forecast grid loads the Project provides a cheaper and cleaner option for Yukon Energy and Yukon ratepayers.

4.3 RISKS AND POTENTIAL IMPACTS ON RATEPAYER COST SAVINGS

The ratepayer cost savings for the Project compared with new diesel generation as forecast in Table 4-3 are subject to a range of economic risks, including capital cost risks, fuel cost risks and grid load risks. The Project as proposed by Yukon Energy at this time also involves a range of risks related to regulatory schedule delays due to the YESAB environmental and socio-economic review process, the Part 3 YUB review process and subsequent permitting and licensing that would follow from these reviews.

Economic Risks Affecting Ratepayer Cost Savings

Ratepayer cost savings in any year as forecast in Table 4-3 reflect the extent to which (a) annual fuel cost savings from use of LNG-supplied gas to displace diesel fuel more than offset (b) annual capital cost charge penalties resulting from higher capital costs needed for the Project compared with the new diesel generation alternative. The main economic risks that could reduce forecast ratepayer cost savings in any year can accordingly be summarized as follows:

1. **Risks that increase annual capital cost charge penalties from the Project**, for example: higher than assumed Yukon Energy capital costs of $38.8 million for the Project (which could reflect a wide variety of potential factors, including costs arising from delays), faster than assumed depreciation of these capital costs, and/or higher than assumed YEC annual costs of capital (costs for debt and equity); and
2. **Risks that reduce annual fuel cost savings from the Project,** for example: lower diesel fuel prices than 24.6 c/kW.h [$1.0513/litre at Whitehorse], higher AECO natural gas prices than $4.5/MMBtu[49], higher LNG haul costs than 4.4 cents/kW.h [assumes A-Train from Calgary], and/or lower long-term average thermal generation requirements than the 17 GW.h forecast in 2015 and higher requirements forecast in subsequent years (which could reflect lower grid loads and/or the impact of new renewable generation on the grid).

To simplify sensitivity analysis of ratepayer cost savings related to these risks, the following analysis assumes that the Project's full 13.1 MW of new natural generation is developed by the end of 2014 (so that the first full year of operation is 2015), and that the Project is compared with the same capacity (13.1 MW) of new diesel that is assumed to otherwise be all installed by the end of 2014.

Based on the above simplifying assumptions, Table 4-4 and Table 4-5 below provide analysis defining a range of possible risk impacts to be considered regarding annual capital charge penalties and annual fuel costs savings related to the Project.

[49] $4.26/GJ (one GJ=0.9471 MMBtu).

Table 4-4: Range of Capital Cost Increases Examined

Capital Cost Sensitivity: 13.1 MW LNG versus New Diesel ($million)

		Added LNG Cost over Table 4-3			
	Table 4-3	5%	10%	15%	20%
Diesel[1]	32.8	32.8	32.8	32.8	32.8
LNG	38.8	40.7	42.6	44.6	46.5
Penalty	6.0	7.9	9.9	11.8	13.8
Annual	0.474	0.626	0.779	0.932	1.085

Maximum Annual Cost Penalty assumes 40 yr depreciation, Year 1 return at 5.45%

1. Diesel capital cost assumes $2.5 million per MW for 13.1 MW (Table 4-3 estimates $33.6 million capital cost for 13.4 MW, or $2.5 million per MW).

Table 4-4 sets out a range of Project capital cost increases (i.e., increases ranging up to 20% above the Project capital costs of $38.8 million [all three engines] as estimated in Table 4-3):

- This analysis is used to define a range of potential capital cost penalties for the Project based on the Project capital cost versus an assumed capital cost for the New Diesel option (assumed capital cost of $2.5 million per MW).
- The penalty under these assumptions is estimated at $6.0 million at the Project's estimated capital cost (per Table 4-3)[50], increasing to $13.8 million if Project capital costs increase by 20%.
- Annual cost charge penalty amounts in Table 4-4 reflect ratepayer depreciation and return costs for each capital cost penalty amount shown over the range of Project capital costs examined in Table 4-4, i.e., $0.474 million/year at the $38.3 million Project capital cost, increasing to $1.085 million/year with 20% increase in Project capital cost.
- The Project's overall economic feasibility is relatively insensitive to capital cost increases, e.g., with forecast fuel cost savings of 11 cents/kW.h and 2015 forecast diesel displacement of 17 GW.h, forecast first year fuel cost savings equal $1.87 million and these savings would continue to exceed capital cost penalties until capital cost increases exceed about $17.5 million (about 45% increase in Project capital cost).

[50] In Table 4-3, the penalty at full development is slightly lower (at $5.1 million) due to the assumption that slightly more New Diesel is developed (13.4 MW) at a total capital cost of $33.65 million.

Table 4-5: Range of LNG Fuel Cost Savings Examined

LNG Fuel Cost Saving ($/kW.h)			
New Diesel	LNG		LNG Saving
		A-Train from Calgary with 18% premium	
0.246	0.115	gas at $3.5/MMBTu, efficiency 44%	0.131
0.200	0.115	gas at $3.5/MMBTu, efficiency 44%	0.085
0.246	0.135	gas at $4.5/MMBTu, efficiency 40%	0.111
0.200	0.135	gas at $4.5/MMBTu, efficiency 40%	0.065
		Tridem from Calgary with 10% premium	
0.246	0.133	gas at $3.5/MMBTu, efficiency 44%	0.113
0.200	0.133	gas at $3.5/MMBTu, efficiency 44%	0.067
0.246	0.154	gas at $4.5/MMBTu, efficiency 40%	0.092
0.200	0.154	gas at $4.5/MMBTu, efficiency 40%	0.046

Table 4-5 sets out a range of annual fuel cost savings (i.e., fuel cost savings that range from 13 cents/kW.h down to 5 cents/kW.h, as compared to the 11 cents/kWh delivered fuel cost saving assumed in Table 4-3 for gas supplied by LNG versus diesel fuel).

- The range of fuel cost savings is shown with new diesel engines[51] and based on a range of diesel fuel costs (20 cents and 24.6 cents per kW.h), AECO gas prices ($3.5/MMBtu and $4.5/MMBtu)[52] and two LNG haul options from Calgary to Whitehorse (A-Train and Tridem trailers).
- The Project's overall economic feasibility requires fuel cost savings and is therefore sensitive to reductions in fuel cost savings below a certain level, e.g., with forecast capital costs of $38.8 million (annual cost penalty of $0.474 million per Table 4-4) and 2015 forecast diesel displacement of 17 GW.h, forecast first year fuel cost savings would continue to exceed annual capital cost penalties until fuel costs savings fall below about 2.8 cents/kW.h[53].

To link the above two sets of risks (capital and fuel costs), Table 4-6 below shows the minimum long-term average annual diesel displacement required under each set of risks for fuel cost savings from the Project to offset the capital cost penalties from the Project in the first year of operation (annual capital cost penalties will gradually decline after the first year of operation due to depreciation impacts). For example, with fuel cost savings at $0.11/kW.h, 9.9 GW.h/year [or more] of diesel displacement would be needed in the first year of operation to offset capital cost penalties with a 20% increase in Project capital costs; however, with fuel cost savings at only $0.05/kW.h, 21.7 GW.h/year [or more] of diesel displacement would be needed in the first year of operation to offset capital cost penalties with the same 20% increase in Project capital costs.

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[51] Fuel costs with existing diesel engines on average approximate 28.7 cents/kW.h.

[52] $4.26/GJ (one GJ=0.9471 MMBtu).

[53] Based on the assumed Project capital cost and 2015 diesel displacement, overall Project cost savings for ratepayers would continue at AECO gas prices up to at least $13/MMBtu (assuming diesel fuel prices at 24.6 cents/kW.h with new diesel engines and LNG is transported with A-Trains as assumed from Calgary).

Table 4-6: Ratepayer Cost Savings Sensitivity to Project Capital Costs and Fuel Cost Saving Risks

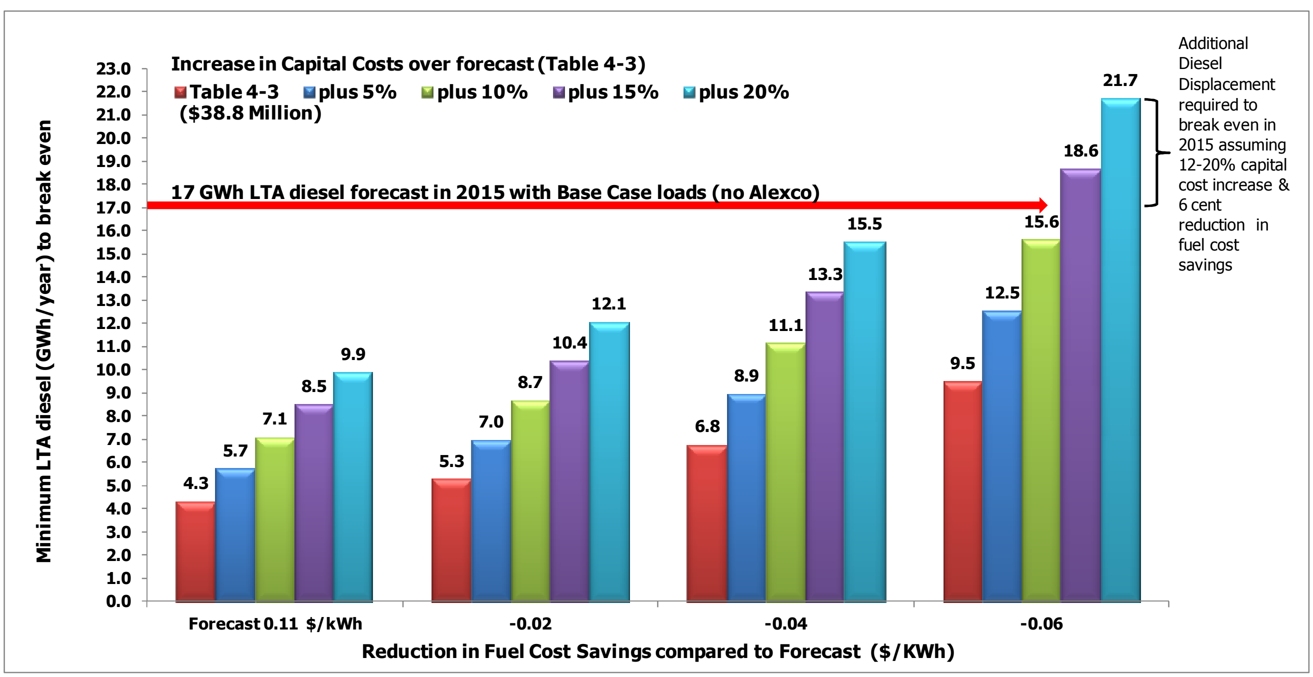
Maximum Annual LNG Capital Cost Penalty at 13.1 MW ($million/yr)[1]

LNG Fuel Cost Saving[2] ($/kW.h)	0.474	0.626	0.779	0.932	1.085
	Table 4-3	plus 5%	plus 10%	plus 15%	plus 20%
	(Minimum LTA Displaced Diesel [GW.H/yr] to Break Even)				
0.13	3.6	4.8	6.0	7.2	8.3
0.11 Table 4-3	4.3	5.7	7.1	8.5	9.9
0.09	5.3	7.0	8.7	10.4	12.1
0.07	6.8	8.9	11.1	13.3	15.5
0.05	9.5	12.5	15.6	18.6	21.7

Notes:
1. See Table 4-4 on Capital Cost Sensitivity
2. See Table 4-5 on LNG Fuel Cost Saving
3. 17 GWh LTA diesel forecast in 2015 with Base Case loads (no Alexco)

As shown in Figure 4-1 below, the Project's economics and ratepayer cost savings are very robust. This is highlighted by the fact that under Base Case loads for 2015 (with forecast LTA diesel displacement at 17 GW.h) ratepayers would continue to secure cost savings from the Project under all of the sensitivities examined other than when the lowest fuel cost savings level is assumed ($0.05/kW.h, or a reduction of $0.06/kW.h below the forecast $0.11/kWh saving) **in combination with** an increase in Project capital costs in excess of about 12%.

Figure 4-1: Capital Cost & LNG Fuel Cost Savings Sensitivity



Specific economic risk sensitivities of the Project are examined below in more detail:

1. **Capital Cost Sensitivity:** There is a risk that Project capital costs may exceed forecasts for a number of reasons, including: higher than originally forecast costs for required regulatory reviews; higher than forecast planning costs to deal with site layout redesign to avoid need to lease private lands; construction delays due to regulatory/ licencing processes not being completed in time to meet the May 1, 2014 start of construction; added costs related to mitigation measures and/or modifications to Project design; tendered construction costs being higher than forecast; or due to complexities related to construction or unforeseen site conditions. The sensitivity analysis in Table 4-6 regarding impacts on Project economics of higher than forecast capital costs (increases ranging from 5% to 20% over currently forecast Project capital costs of $38.8 million) indicates as follows:
    a. Assuming 40 year depreciation and year 1 return of 5.45%, the $0.5 million annual capital cost charges penalty for LNG compared to the new diesel alternative increases by $0.153 million with each 5% increase in cost over the forecast of $38.8 million.
    b. With the incremental annual cost premium for each 5% incremental increase in cost over forecast (from 5% to 20%) there continue to be fuel cost savings under Base Case loads (with no Alexco) under a range of conditions.
        i. With a 5% or 10% increase in capital cost, and with diesel forecasts based on Base Case loads (with no Alexco), the Project would remain economic at fuel cost savings up to 6 cents/kWh lower than forecast.
        ii. With a 15% or 20% increase in capital cost, and with diesel forecasts based on Base Case loads (with no Alexco), the Project would remain economic at fuel cost savings up to 4 cents/kWh lower than forecast.
        iii. With a 15% to 20% capital cost increase, and fuel cost savings 6 cents/kWh lower than forecast, the Project would not break even until the minimum LTA diesel displaced (GWh/year) at least equals 18.6 GWh for a 15% cost increase over budget or 21.7 GWh for a 20% cost increase over budget. Considering Table C-2 in Appendix C, LTA diesel displacement under Base Case loads (no Alexco) is only 17 GWh in 2015 and 22.9 GWh in 2016, but increases to 26.9 GWh by 2017 and 31.4 GWh by 2018.
2. **LNG Fuel Cost Savings Sensitivity:** There is a risk that the assumed annual fuel cost savings for the Project with LNG compared to the new diesel alternative may be reduced due to changing market conditions (affecting the price of LNG compared to diesel), differences in efficiency, or due to increased LNG transportation costs (e.g., due to requirement to rely on Tridem trailers for transport in initial years due to A-Train trailers not being permitted or available and/or increased costs due to lower initial loads). The sensitivity analysis in Table 4-6 regarding impacts on Project economics of changes in LNG fuel cost savings (range from 13 cents/kW.h down to 5 cents/kW.h, as compared to the 11 cents/kW.h delivered fuel cost saving assumed in Table 4-3 for gas

supplied by LNG versus diesel fuel) indicates as follows:

a. With A-Train Trailers from Calgary (and including an 18% premium to account for potential inefficiencies in early year operations due to lower load requirements) fuel cost savings may range from 13 cents/kWh (with assumed diesel price of 24.6 cents/kWh, $3.5/MMBtu gas cost and generation engine efficiency of 44%) to 7 cents/kWh (with 20 c/kWh diesel cost and higher gas cost of $4.5 MMBTu and efficiency of 40%).

b. With Tridem trailers from Calgary (and including a 10% premium to account for potential inefficiencies in early year operations due to lower load requirements) fuel costs range from 11 cents/kWh (with assumed diesel price of 24.6 cents/kWh, $3.5/MMBtu gas cost and efficiency of 44%) down to 5 cents/kWh (with 20 cents/kWh diesel cost and higher gas cost of $4.5 MMBTu and efficiency of 40%).

c. Table 4-6 indicates that with only 7 cents/kWh fuel cost savings the Project remains economic and achieves savings under Base Case load scenarios (without Alexco). With only 5 cents/kWh fuel cost saving the Project remains economic under Base Case load scenarios (without Alexco) assuming that Project capital costs remain within 10% of the forecast in Table 4-3.

3. **Sensitivity to LTA Default Diesel Forecast Risk:** There is a risk that grid loads, and specifically the forecast default LTA diesel generation requirement, may not materialize as forecast. Forecast grid loads may potentially be reduced below the Base Case forecast in Appendix C due to loss of industrial load (Minto) and/or reduced residential/ commercial load due to economic downturn, or due to DSM/ conservation programs being more successful than currently forecast. Forecast of LTA default diesel for the grid may potentially be reduced below Base Case forecast in Appendix C due to lower grid loads than forecast and/or due to new renewable generation coming into service on the grid to displace default diesel that would otherwise be forecast.

   a. Load related risks tend to be minimal for the Base Case load scenario reviewed in Appendix C (as this scenario deals largely with new generation capacity otherwise required with currently connected mine loads, long-term growth rates for non-industrial loads, and DSM/SSE assumptions that reflect YEC/YECL near-term plans).

   b. Further, the Base Case scenario assumed in Table 4-3 excludes Alexco, a connected mine load that may well reopen within the next one to two years (reopening of Alexco would materially increase forecast near-term default diesel as shown in Appendix C).

   c. As reviewed in Section 4.2.2 of the Application, potential near-term hydro enhancement projects at Mayo Lake and Marsh Lake would respectively supply 4 and 6 GW.h/year of LTA incremental energy and at most one MW of added firm winter capacity (Marsh Lake Storage) with potential in-service impacts at the earliest in 2016 and 2017 respectively. Overall, under Base Case load forecasts these two renewable resource projects together would still leave forecast default grid diesel generation in 2017 at approximately 17 GW.h, with forecast default diesel increases in subsequent years due to forecast load growth.

Management of Key Project Risks

Prior to YEC's Board of Directors approving each major stage of Project development, all material risks are reviewed to confirm that it is prudent to proceed. In assessing Project risks, Yukon Energy also considered seriously the potential exposure to material additional diesel generation costs that may arise should the Project not proceed at this time in order to be in service for winter 2014/15. YEC proposes to manage and address remaining risks related to regulatory or other delay, capital cost increases and construction risks and other project feasibility risks as outlined below.

- **Regulatory/ Schedule risks** – Exist to the extent that permits and approvals are not available, or weather conditions are not favourable, to allow construction activities to commence as planned starting May 1, 2014. Delay of Project construction beyond May 1, 2014 threatens the ability to complete Project construction in the 2014 summer construction season and the ability to have the Project in service before the end of Q4 2014 in order to be available to displace diesel requirements in the winter of 2014/2015. Delay of Project in service also increases the risk of YEC incurring added capital costs. Not having the Project in service by the end of 2014 means that the Project will not be in place to reduce ratepayer fuel costs in the first half of 2015 by approximately $2.1 million[54] and that new thermal generation capacity for reliable service will also not be available as required during that winter.
  - Most regulatory requirements are reasonably apparent and Yukon Energy has through the CSTP and Mayo Hydro Enhancement Project (Mayo B) developed considerable experience with navigating the assessment and regulatory processes involving YESAB and the Yukon Government. Where new processes exist (e.g., Yukon Gas Processing Plant Regulations), Yukon Energy is proactively consulting with the relevant regulators to ensure adequate understanding of regulatory requirements and processes.
  - Throughout the Project development and review process, Yukon Energy has been working in consultation with key stakeholders such as TKC and KDFN, as well as regulators to ensure any issues or concerns with the Project are addressed proactively and expeditiously. However, notwithstanding Yukon Energy's past experience of timely progress with CSTP and Mayo B reviews after release of the Draft Screening Report, risks remain that the YESAB and related Decision Body Approval processes may be delayed and result in delays to the start of Project construction beyond May 1, 2014. YEC will be undertaking all measures within its control to prevent and/or minimize such delays.

  YEC anticipates minimal environmental or regulatory cost risks arising from the YESAB and other permitting processes. While LNG is new to Yukon, LNG technology has been in use across Canada and around the world for decades. The standards, codes and regulations that must be

[54] Estimated based on long-term average thermal generation of more than 14 GW.h for Base Case load forecast (no Alexco) over the six month period from January 1, 2015 to June 30, 2015; reflects the difference between estimated diesel fuel cost of $4.02 million with existing diesel units (based on Yukon Energy's 2012/13 GRA Compliance Filing average diesel fuel generation cost of 28.7 cents/kW.h), and $1.89 million with new LNG units (based on LNG fuel cost at 13.5 cents/kW.h with 100% diesel displacement, and assuming A-train LNG transportation is established and an AECO gas price of $4.5 per MMBtu).

met in order to transport LNG and to construct and operate an LNG facility safety are well known and understood in the industry[55].

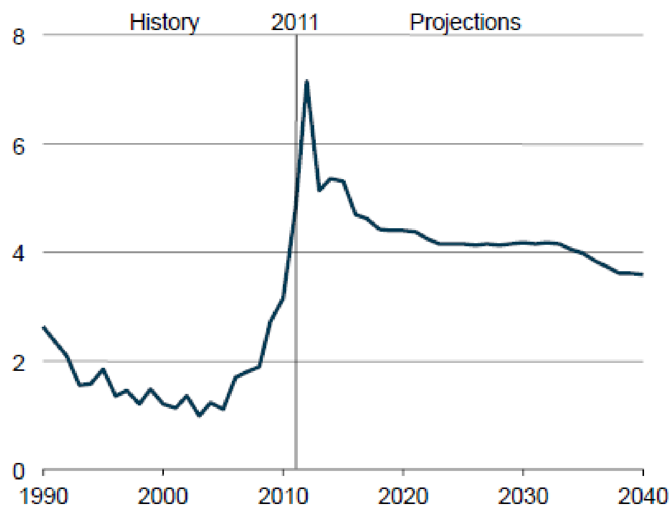
- **Capital cost increase risks and other construction risks** – May be expected for any project of this nature, location, and stage of development. Added risks (and costs) may also arise related to tight timing required to meet a Q4 2014 in service date. As noted above, the Project economics are robust under a number of varying capital cost and LNG fuel cost savings conditions.
  - The GE Engines are the largest cost component for the Project (33% of total WTGS capital costs) – there is a high degree of certainty regarding this cost component as Yukon Energy has entered into an EPC contract with GE/ Gas Drive to engineer, build, deliver and install the units (including related switchgear) on site.
  - YEC is also concluding at this time contract arrangements related to the key LNG facilities equipment, including storage tanks and vapourizer.

4. **LNG Fuel Cost Risks** – There is a risk that the assumed annual fuel cost savings with LNG compared to the new diesel alternative may be reduced due to changing market conditions (affecting the price of LNG compared to diesel), differences in efficiency, or due to increased LNG transportation costs (e.g., due to requirement to rely on Tridem trailers for transport in initial years due to A-Train trailers not being permitted for available and/or increased costs due to lower initial loads).
   a. As regards specific near-term assumed oil and gas prices, Table 4-3 assumptions reflect recently approved YEC diesel fuel prices at Whitehorse and an assumed AECO gas price (at $4.5/MMBtu) that is well above recent AECO gas prices that approximated $3.5/MMBtu in November 2013.
   b. With regard to the concern that overall market conditions may change such that LNG or natural gas advantage is reduced materially as a low cost fuel option relative to oil products such as diesel, it is noted that interest today in LNG development, including active ongoing consideration of various LNG export opportunities from British Columbia to Asia[56] as well as development of new LNG production facilities in western Canada to supply domestic markets, reflects expectations that the major gap between North America natural gas prices and world crude oil prices (on an equivalent price per Btu basis) will likely be sustained for the next 20 years or more into the future. Just prior to 2010, the gap increased dramatically between world crude oil prices and natural gas prices in North America, and crude oil price is expected, in the latest forecast outlook (April 2013) provided by the U.S. Energy Information Administration, to remain well

[55] See also, Section 6.2 of this Application (Conditions Affecting Approvals) and discussion in Section 3.4 (Summary of Environmental and Socio-economic Effects).
[56] LNG export opportunities from BC to Asia are based on the expectation of a sustained gap between high gas prices in Asia and much lower gas prices in North America. Gas prices in Asia tend to be linked to international crude oil prices, unlike the situation today in North America.

above North America natural gas prices through to at least 2040[57]. These forecasts indicate crude oil prices to be 4 times that of North America natural gas price with the expectation that this condition would continue for a period extending beyond 2030 (see Figure 4-2 below).

Figure 4-2: Ratio of Brent Crude Oil Price to Henry Hub Spot Natural Gas Price in Energy Equivalent Terms, 1990-2040



Source: U.S. Energy Information Administration; Annual Energy Outlook 2013 (USEIA 2013)[58].

c. Yukon Energy has been working with Western Copper and Gold and PROLOG Canada Inc. to secure permitting for an A-Train Trailer with 95.3 m^3 net capacity (Yukon approvals have been secured, and now attention is being focused on securing Alberta and British Columbia approvals).

5. **Security of LNG Supply** - LNG supplies are planned to be available in the fourth quarter 2014 from southern Alberta (Shell Canada's new plant near Calgary) and southern British Columbia (Fortis's facility in Delta); Yukon Energy has contract arrangements with Shell Canada as reviewed in the Application. A Ferus/Encana liquefaction facility is also being developed to start production in 2014 at Grande Prairie, Alberta, two new LNG liquefaction plants to be located in Vancouver and Edmonton by 2016 have recently been announced by a joint venture of Ferus Natural Gas Fuels and ENN Canada Corporation, and an expansion of the FortisBC Tilbury LNG liquefaction plant in Delta has been announced for mid-2016. Yukon Energy has also worked with Western Copper and Gold and Spectra Energy (as well as others) to examine future opportunities for LNG supply to be developed at the much closer location of Fort Nelson, BC.

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[57] U.S. Energy Information Administration; Annual Energy Outlook 2013 (USEIA 2013). This report's Reference Case forecast expects Henry Hub spot prices for natural gas (2011$) to increase by an average of about 2.4 percent per year, from $3.98/MMBtu in 2011 to $7.83/MMBtu in 2040. Over this same period the report expects Brent crude oil prices (2011$) to increase from $19.18/MMBtu in 2011 to $28.05/ MMBtu in 2040.
[58] http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf.

Risk of Not Proceeding with the Project

Deferring replacement of the diesel units would expose all grid customers to unreliable generation capacity as well as higher O&M costs, and replacement by thermal generation units would be required in any event as soon as feasible.

Other Benefits related to the Project

The Project provides the following benefits that enhance Yukon Energy's ability to address risks and other contingency events on the integrated grid:

- Yukon Utilities Board Order 2013-1 recently directed Yukon Energy, for the purpose of approved revenue requirements used to set rates for 2012 and 2013, to forecast hydro and diesel requirements assuming 100% long-term average hydro generation. This direction re-establishes the full benefit savings to ratepayers, determined using long-term average hydro generation (i.e., without uncertainties of forecasting actual hydro generation each year) of changing from diesel to lower cost reliable generation than displaces diesel generation requirements[59].
- LNG development will reduce ratepayer exposure to severe and periodic drought related cost risks. For example, with 2016 Base Case grid loads and no LNG-based gas engine generation, in the five consecutive worst drought years (based on water flows in the 1996-2000 period), Yukon Energy would be exposed to diesel generation from 52.8 to 101.4 GWh/year[60]. Gas engine capacity at approximately 9 MW, as proposed to be installed by late 2014, will enable Yukon Energy, at 2016 Base Case load to reduce this diesel exposure during drought years such that diesel generation would be forecast to exceed 5 GWh in only 1 out of 31 years, with diesel generation in that year reduced 101.4 to 31.1 GWh/year[61].
- The Project's LNG development cost savings could be enhanced to the extent that lower natural gas prices are realized than the $4.5/MMBtu assumed in Yukon Energy's analysis, arrangements are made with Shell to facilitate lower cost delivery of LNG through provision of LNG to Yukon Energy at Fort Nelson, LNG powered trucks are implemented to reduce shipping costs, or district energy heat sales are realized from LNG.

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[59] Variances [at GRA approved fuel prices] between actual diesel generation costs and expected diesel generation costs for each year (based on actual grid loads) are accounted for through the Diesel Contingency Fund (where funds are held in trust on behalf of ratepayers to help stabilize rates relative to cost variances caused by annual changes in hydro water flows). Variances in actual diesel fuel prices from approved GRA fuel prices are accounted for through Rider F provisions with charges or credits passed through to ratepayers based on actual energy use.

[60] See Appendix C, Table C-3.

[61] See Appendix D, Table D-2.

5.0 CONSULTATION

5.1 YESAB PROCESS

The key elements of the Whitehorse Diesel – Natural Gas Conversion Project have undergone extensive consultation under Yukon Energy's 2011 20-Year Resource Plan: 2011-2030 ("2011 Resource Plan"), YEC's planning for the Project's YESAB Project Proposal, and the YESAB screening of the Project Proposal Submission.

LNG was identified in Yukon Energy's 2011 20-Year Resource Plan as a potential source to displace near-term grid diesel requirements. It has been examined as a new fuel option that retains flexibility for power generation as well as diversity for energy use opportunities.

5.1.1 Public Consultation Prior to YESAB Submission Filing

Yukon Energy began engaging Yukoners in discussions about upcoming electrical planning requirements with the review of the 2006 20-Year Resource Plan: 2006-2025 by the YUB. In that document, grid capacity planning criteria were provided and the need to replace or significantly refurbish aging diesel thermal generation units was examined.

Discussions about energy choices, including the need for back-up thermal generation capacity given the nature of a hydro-based system, continued as part of a three day public energy Charrette held in March 2011 in Whitehorse leading up to the draft Yukon Energy 2011 Resource Plan. As part of the 2011 Resource Plan process, four criteria for evaluation and decision-making regarding energy technology choices were developed: reliability, affordability, flexibility and environmental responsibility. Following up on the energy Charrette, Yukon Energy continued to host technology-specific workshops including a public workshop in Whitehorse in January 2012 on the potential use of LNG for electrical generation. Subsequent to this extensive public engagement process the draft 2011 Resource Plan was made publically available for review in July 2012.

During 2012, Yukon Energy began to explore specific opportunities at its Whitehorse site to install new natural gas generators (supplied by LNG) to replace aging diesel generators that must be retired.

Both KDFN and TKC were invited in May of 2012 to initiate discussions with Yukon Energy regarding potential economic opportunities with respect to such a project. A partnership committee was developed, including the signing of Confidentiality Agreements and Terms of Reference in July 2012. Numerous briefings have also been provided to both Chiefs and Councils and First Nation citizens, including elders, by Yukon Energy officials and First Nation representatives. Additional meetings were conducted during the first week of July 2013.

During 2012 and 2013, prior to filing with YESAB, Yukon Energy briefed the Whitehorse City Council and City Planning officials with respect to potential plans for the Project. Additional stakeholder meetings and a public open house in the first two weeks of July 2013 provided another round of public engagement on the potential use of natural gas and more detailed information about the proposed Project. These events also provided an opportunity to discuss proposed valued components with the various stakeholder groups and solicit additional feedback.

Yukon Energy also engaged in ongoing formal and informal contact with various regulatory authorities prior to filing with YESAB to address potential areas of interest with regard to the Project, including safety, emissions and land tenure, and will maintain dialogue with these parties throughout the review process.

Appendix B of this Application provides additional details on consultation up to the filing with YESAB of the Project Proposal Submission.

5.1.2 YESAB Consultation Process

After completing the above noted stages of consultation, Yukon Energy submitted a Project Proposal to the Executive Committee of YESAB in August 2013 whereby YESAB initiated its pre-screening process, which reviewed the adequacy of the Project Proposal and included requests for supplementary information (October 2013). During the adequacy review, YESAB received comments from KDFN, TKC, and Yukon Government.

Following the submission of the Project Proposal, KDFN submitted a letter in support of the proposed Project to the Executive Committee. Both TKC (August 21, 2013) and KDFN (August 15, 2013) notified YESAB of their satisfaction with Yukon Energy's consultation as it relates to Section 50(3) of the *Yukon Environmental Socio-Economic Assessment Act*.

The following milestones were achieved in November 2013:

- November 1, 2013: YESAB Executive Committee announced that the Whitehorse Diesel – Natural Gas Conversion Project had successfully completed their Adequacy Review and could commence the Screening and Public Review Phase.
- November 5, 2013: A public notice was posted on the YESAB Online Registry to inform the general public of a 30-day public review period from November 5 – December 6, 2013.
- November 20, 2013: The public review period was extended to December 20th to accommodate additional proposal information Yukon Energy submitted to YESAB on November 13, 2013.

The Project proposal, supplementary filings, Project-related announcements from YESAB, and any public comments received are all available on the YESAB Online Registry at: http://www.yesab.tzo.com/wfm/launch/YESAB. The Project proposal is also available on the Yukon Energy website (www.yukonenergy.ca).

6.0 OTHER APPLICATIONS AND APPROVALS

6.1 LIST OF APPROVALS, PERMITS AND LICENCES

Numerous regulatory approvals and decisions are required before construction activities can be initiated; however, these approvals and decisions may only be made after the required effects assessment for the Project is completed by the Executive Committee under the *Yukon Environmental and Socio-economic Assessment Act* ("YESAA").

The Project is subject to a screening level assessment by the Executive Committee of YESAB, in accordance with Section 26 of Schedule 3 of the *Assessable Activities, Exceptions and Executive Committee Projects Regulations* as the Project will involve the expansion of a fossil-fuel fired electrical generating station that potentially increases production capacity by 5 MW or more prior to consideration of the concurrent decommissioning of WD1 and WD2 units at this station, i.e., the Project will increase the production capacity of the WTGS by up to 13.1 MW.

A review of the Project is also required by the YUB under Part 3 of the *Yukon Public Utilities Act*, and by the Yukon Oil and Gas Branch under the *Oil and Gas Act (Yukon), Gas Processing Plant Regulation.*

Table 6-1 lists the regulatory permits and approvals that have been identified as being potentially required for the Project.

Table 6-1: Regulatory Authorizations Required for the Project

Activity	Authorization Required	Act or Regulation
Pressure piping system	Approval and Registration of Design	*Boiler and Pressure Vessels Act*
Permission to obtain gravel/sand from a quarry	Quarry Permit	*Territorial Lands (Yukon) Act, Quarry Regulations, Lands Act*
Clearing timber	Land Use Permit	*Territorial Lands (Yukon) Act, Land Use Regulations, Lands Act*
Tenure for land lease or agreement of sale, or other disposition	Land Disposition	*Territorial Lands (Yukon) Act, Territorial Lands Regulation, Lands Act, Lands Regulations*
Registration of an interest in land	Land Title Registration	*Land Titles Act*
Gas Piping	Gas Installation Permit	*Gas Burning Devices Act*
Use of natural gas in a gas burning device	Gas Installation Permit	*Gas Burning Devices Act*
Electrical work	Electrical Permit	*Electrical Protection Act; Canadian Electrical Code*
Handling, disposal, generation or storage of special (hazardous) wastes	Amendment to existing Hazardous Substances Aboveground Storage Tank Permit	*Environment Act, Storage Tank Regulations*
Operation of electricity generating facilities with a maximum nameplate capacity equal or more than 1.0 Megavolt ampere (or 1 MW)	Amendment to existing Air Emissions Permit	*Environment Act, Air Emissions Regulation*
Transport of dangerous goods/waste	Permit for transport of dangerous goods	*Dangerous Goods Transportation Act, Dangerous Goods Transportation Regulations*
Erect a sign within highway right of way	Sign Permit	*Highways Regulation*
Construction of a project designated as an "energy project" under Part 3 of the *Public Utilities Act*	Energy Project Certificate	*Public Utilities Act*

Activity	**Authorization Required**	**Act or Regulation**
Operation of a project designated as an "energy project" under Part 3 of the *Public Utilities Act*	Energy Operation Certificate	
Construction and operation of a facility for the storage and vaporization of liquefied natural gas	Facility Licence	*Oil and Gas Act (Yukon), Gas Processing Plant Regulation*
Construction of an oil and gas facility	Construction Authorization	
Operation of an oil and gas facility	Operation Authorization	
Development within the City of Whitehorse	Development Permit	*City of Whitehorse – Zoning Bylaw, Development Agreement Regulations Bylaw (Bylaw 2012-15)*
Creation of a new lot within City of Whitehorse boundary	Authorization to subdivide	*City of Whitehorse -Subdivision Bylaw (Bylaw 2012-16)*
Work within 4 km of aerodrome property	Transport Canada Obstacle Clearance Form	*Canadian Aviation Regulation* *TP 312 Standards and Recommended Practice*

Before any Yukon permit or approval can be issued, YESAB must complete its screening report and make recommendations to the relevant Decision Bodies under YESAA. Further, each Decision Body must also issue Decision Documents agreeing with the YESAB recommendations before any permits or approvals can proceed. For the Project, the Yukon Government is the sole Decision Body.

YESAB's Final Recommendations Report on the Project will be submitted to the Yukon Government, Development Assessment Branch of Executive Council for issuance of a Decision Document for ministerial approval. To facilitate moving quickly through the final decision and permitting phase, steps are being taken well in advance of the YESAB's Final Recommendations Report being issued to initiate actions by relevant decision and permitting bodies in advance of a draft YESAB screening report.

Timely completion of the draft YESAB screening report is also critical to the overall planning approach since it will provide the Decision Body, as well as YEC, with an opportunity for early review of YESAB's assessment and draft recommendations. This initial review will provide the opportunity for any significant issues or differences between various decision and assessment parties to be resolved prior to the issuance of the YESAB Final Recommendations Report[62].

6.2 CONDITIONS AFFECTING APPROVALS

Yukon Energy does not anticipate material risks of major design modifications resulting from regulatory approvals and review process for this Project. The proposed Project will be built using conventional construction technologies suited for northern climate conditions, and following all applicable construction and design practices for works of this nature, including building and electrical codes and adhering to industry best practices. The technologies employed in the Project for the LNG facilities and the GE J624 modular gas-fired engines are industry standard in all material respects and proven in northern climate conditions. The Project will also adhere to all applicable national and territorial standards used in the design of all Project components.

Stringent standards and regulations for design, construction and operation for LNG transport, storage and vapourizaton facilities have developed over the last 40 years to prevent accidents and minimize the adverse impacts of events. LNG facilities must meet all standards, codes and regulations enforced by federal, provincial/ territorial or municipal jurisdictions. Accordingly, no special added costs are anticipated at this time to be required for the Project to comply with anticipated material conditions in approvals or permits.

The major regulatory risk for the Project remains material delays in schedule which could adversely affect Project costs and benefits for ratepayers starting in winter 2014/15.

[62] Section 75(1) of YESAA provides that a decision body must issue a decision document within the period prescribed by the regulations after the YESAB Executive Committee makes a recommendation. The decision document may accept, reject or vary the recommendation. However, under section 76(1) of YESAA, where an Executive Committee makes a recommendation, the decision body must within the prescribed time periods (a) issue a decision document accepting the recommendation or (b) refer the recommendation back to the Executive Committee or panel for reconsideration unless that recommendation was made in response to a previous referral under this section.

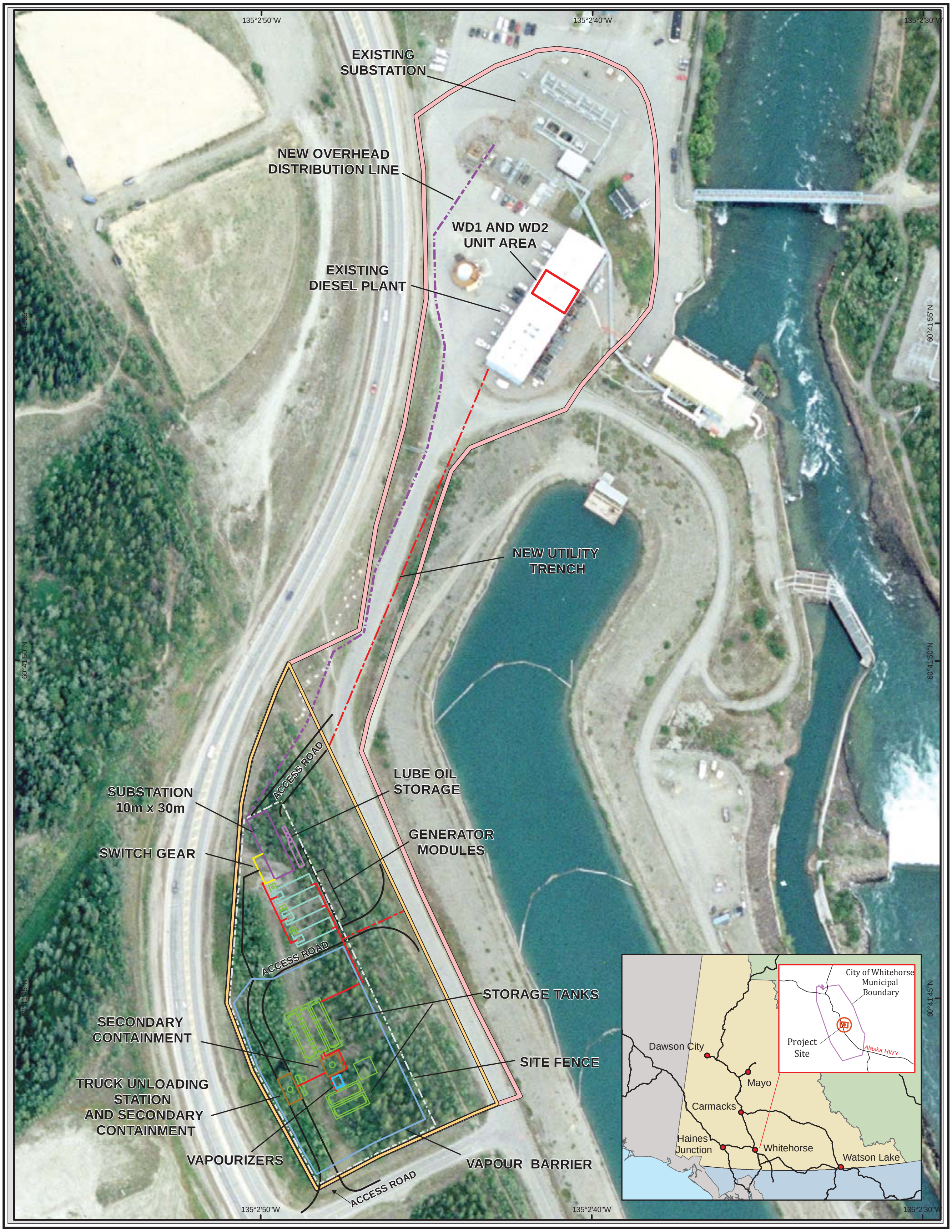
APPENDICES

APPENDIX A

WHITEHORSE THERMAL GENERATING STATION AND PROJECT CONSTRUCTION FOOTPRINT

(REVISION 2 TO FIGURE 2-1 OF THE PROJECT PROPOSAL PROVIDED TO YESAB IN THE NOVEMBER 15, 2013 REVISED PROJECT PROPOSAL)

Document Path: G:\Project Data\LNG\MAPS\2-1_revA Fig_LNG WTGS_Project Construction Footprint_14Nov2013.mxd



Data Source -Main Map: Coordinate System: NAD83 UTM Zone 8
City of Whitehorse 2006 digital image

Data Source -Overview Map: Coordinate System: Yukon Albers
NTDB 2009, 1:1,000,000 Place Names
Canadian Administrative boundaries, Geobase 2013
*All data are limited by the date the map was printed. All spatial data subject to change.

N W E S

1:1,600
Meters
0 20 40 80 120

This drawing has been prepared for the use of Yukon Energy and may not be used, reproduced or relied upon by third parties, except as agreed to by Yukon Energy and its Partners, as required by law or for use by governmental reviewing agencies. Yukon Energy accepts no responsibility, and denies any liability whatsoever, to any party that modifies this drawing without Yukon Enery's express written consent.

Legend

- Expanded Area
- WTGS and Project Construction Footprint
- Vapour Barrier
- WD1 and WD2 Unit Area
- New Overhead Distribution Line
- Utility Trench
- Storage Tanks
- Fencing (Shown in white)
- Piping
- Lube Oil
- Modules
- Access Road
- Secondary Containment
- Substation
- Switchgear
- Vapourizers

YUKON ENERGY

Whitehorse Diesel - Natural Gas Conversion Project

Whitehorse Thermal Generating Station (WTGS) and Project Construction Footprint

Author: S.Mallory
Reviewed by: H. Campbell
Date Produced: 15/11/2013

Figure 2-1 rev2

APPENDIX B

OVERVIEW OF CONSULTATION ACTIVITIES

APPENDIX B: OVERVIEW OF CONSULTATION ACTIVITIES

As discussed in Section 5 on Consultation, Chapter 4 of the Project Proposal Submission to YESAB provides the primary source of information on consultation activities. Table B-1 below provides a summary of the contents of Chapter 4, including a description of how consultation activities were approached, guiding principles, methods used, key meeting dates, and the public's influence on the Project.

Table B-1: Overview of the Contents of Chapter 4

Section	Contents	Page
4.0 First Nations and Other Publics Consultation	4.0 Brief outline of chapter organization.	4-1
4.1 Overview	4.1 Brief description of the regulatory requirements and involved publics.	4-2
4.2 Principles and Approach to Consultation	4.2.1 Guiding Principles – describes the principles used throughout the public and community involvement process.	4-2
	4.2.2 Opportunities prior to YESAA filing – describes the three stages of opportunity for involvement: Pre-feasibility Stage; Feasibility Stage and Project Introduction; and Interest/Issue Identification, Review of Potential Project Effects & Mitigation.	4-3
	4.2.3 Public Communication of the Filing with YESAB – YEC committed to informing the public on its filing, and to continue with open dialogue with local stakeholders such as Kwanlin Dün First Nation (KDFN), Ta'an Kwäch'än Council (TKC), the City of Whitehorse, and local residents.	4-5
4.3 Methods	4.3.1 Face to face Interaction – with KDFN, TKC, Municipal Government & Other Government, and Local Stakeholders & Other Publics.	4-5
	4.3.2 Electronic, Paper and Other Media – including project information on the Yukon Energy website, and event notifications via print, radio and online sources.	4-6
4.4 Review of Public Involvement Activities to Date	4.4.1 Activities involving KDFN and TKC – discussions focused on three groups: 1) Chief and Council, 2) the LNG partners Committee, and 3) KDFN and TKC membership.	4-7
	4.4.2 Municipal and Other Governments – focused on formal and informal discussions with the City of Whitehorse, as well as meetings and discussions with relevant territorial government departments.	4-11
	4.4.3 Local Stakeholders and Other Publics – summarizes discussions with local residents and non-government organizations (e.g., YCOGE, YCS).	4-13

Section	Contents	Page
4.5 Key Interests and Perspectives Heard to Date	4.5 Summarizes interests and concerns raised during public consultation activities.	4-14
	Table 4-4 summarizes interests and concerns raised by members of the public and areas where feedback from public involvement activities was considered in the Environmental and Socio-economic Assessment process.	4-16
4.6 Future Steps in Public Consultation	Anticipated public consultation activities following the submission of a Project Proposal to YESAB throughout the project planning, assessment, development, and operational phases of the Project.	4-27

Appendices

The appendices to Chapter 4 provide supporting documentation to the main text in Chapter 4, including a list of potentially affected or interested parties, electronic, paper and other media communication, materials used throughout the consultation process, and records of personal communications.

Stages of Consultation

There were three stages of consultation activities for the Whitehorse Diesel – Natural Gas Conversion Project.

During the **Pre-feasibility Stage**, Yukon Energy conducted an extensive public engagement program related to the 2011 20-Year Resource Plan[1]; this process included consulting broadly with a number of different stakeholders on the LNG supply option. In preparing the 2011 Resource Plan, Yukon Energy sought input from First Nations and other governments, stakeholders and the public through meetings, workshops and a three-day energy planning charrette held in March 2011[2].

The purpose of the **Feasibility Stage and Project Introduction** was to:

- Keep the key stakeholders that would most be affected by the siting and development of the Project apprised of activities being undertaken; and

[1] This occurred over the course for 2011 and 2012, and in addition to a 3 day energy charrette included several public workshops on resource options (e.g., waste to energy and biomass, DSM, wind and LNG).
[2] The charrette brought together Yukoners from all walks of life as well as nationally and internationally recognized energy experts and reviewed a number of supply options and alternatives including wind, biomass, waste-to-energy, hydro, solar, nuclear, DSM, transmission interconnections and gas/liquefied natural gas (LNG). Information and knowledge was shared and the participants were provided with considerable technical information regarding the resource options reviewed (including LNG) and provided a great deal of input in terms of what Yukon's energy future should look like. Along with providing a list of energy options for future investigation and analysis, the charrette participants also helped Yukon Energy formulate four principles around which to base future energy decisions: reliability, affordability, flexibility and environmental responsibility. Charrette materials, including background papers, presentations, meeting minutes and the charrette report are available at Yukon Energy's website.

- To learn about any key interests and issues from stakeholders that might arise regarding site location and any subsequent decision to move ahead with completing studies and consultation required for a submission to YESAB.

The **Interest/Issue Identification, Review of Potential Project Effects & Mitigation Stage** provided an opportunity for the public (including stakeholders such as KDFN, TKC, the City of Whitehorse and regulators) to express key perspectives and issues about the proposed Project. During this stage Yukon Energy also provided the information to stakeholders regarding the Project, including introductions to the Project and its components/ options and business case, updates regarding status of Project planning activities and schedule, results of baseline studies, site options and issues, LNG supply options considered and status of Whitehorse diesel plant upgrades.

Yukon Energy has continued with on-going consultation with various regulatory authorities to address potential areas of interest with regard to the Project.

APPENDIX C

UPDATED NEAR-TERM GRID LOAD SCENARIOS

APPENDIX C: UPDATED NEAR-TERM GRID LOAD SCENARIOS

The 2011 Resource Plan grid load scenarios as set out in Appendix A to the Overview of 20-Year Resource Plan: 2011-2030 are updated on an ongoing basis (the last update was March 2013). The November 2013 update includes four scenarios to reflect the timing for connection or reopening of mines[1] and the load update for non-industrial and existing mine loads.

Line losses for the Integrated Grid are assumed at 8.7% for all load, including industrial load - this is consistent with 2012/13 GRA approved forecast.

1. Two Base Case load scenarios are examined (assume no connection of major new mines):
   a. **Base Case no Alexco after fall 2013:**
      i. Updated non-industrial forecast load for 2013 and 2014[2], reflecting the following:
         - Non-industrial growth at 2.26%/year for 2015, at 2.45%/year for 2016-2020 inclusive, at 2.82%/year for 2021-2025 inclusive, at 3.13%/year for 2026 and thereafter; and
         - DSM/SSE assumed at 32% of annual load growth based on Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012); to reflect proposed DSM plans (YECL 2013-15 GRA goal of 8.5 GW.h/year sustained electricity savings by 2018), impact reduced for the first year (2015) taking ¼ of the assumed 32%, 2/3 for 2016, and at full 32% starting from 2017.
      ii. Minto generation load (includes grid losses) at 34.6 GW.h/2013, 38.0 GW.h/2014, 40.2 GW.h/2015 and at 43.5 GW.h/year for 2016-2022 (no load thereafter)[3]; and

[1] This update does not include Whitehorse Copper Tailings (WHCT), Brewery Creek and Victoria Gold new industrial loads based on current information WHCT development is currently too uncertain to include in the update. Brewery Creek development was cancelled in early 2013. Victoria Gold received its Quartz Mining Licence for the Eagle Gold Project in September 2013; however, the timing for development is uncertain due to financial market conditions (2016 is the current stated focus to start production).

[2] Non-industrial load forecast for 2013 is based on January-October preliminary actuals and November-December updated forecasts. The 2013 updated YEC non-industrial load forecast (340 GW.h excluding grid losses) is about 2 GW.h lower than 2013 GRA approved forecast due to lower wholesales; however, the GRA approved wholesales forecast included 5.1 GW.h related to WHCT (which did not connect in 2013), i.e., overall updated non-industrial load for 2013 is forecast about 3 GW.h higher than the approved GRA forecast with January-October actuals as reported reflecting warmer than normal temperature conditions. The 2014 forecast is based on YEC's latest update which uses 2.26% growth rate over weather normalized 2013 full-year-forecast wholesales (308.5 GW.h) reduced by 4.36 GW.h to reflect Fish Lake Unit #1 being in operation in 2014. The non-industrial growth rates remain unchanged from the March 2013 update: 2011 Resource Plan forecast annual growth rate for non-industrial load for 2014 and 2015; annual growth rates for 2016-2020, 2021-2025 and 2026-2030 are from Marbek's final CPR report.

[3] Minto generation load forecast reflects updates reviewed with Minto in fall 2013.

iii. Alexco generation load (includes grid losses) at 9 GW.h for 2013 and no load thereafter[4].

b. **Base Case with Alexco:**

i. This scenario assumes Alexco reopens in 2015 with loads similar to what had been forecast in the past, with generation load (includes grid losses) at 15.2 GW.h for 2015, at 17.4 GW.h for 2016 though 2021 (no load thereafter)[5].

2. Load scenarios with connection of major new mines[6]:

a. **Scenario A1 – no Alexco:** Base Case with Carmacks Copper mine, starting January 1, 2018 with generation load (including grid losses) of 54.4 GW.h/yr that continues until the end of 2024 and 27 GW.h/yr for 2025 (no load thereafter)[7].

b. **Scenario A2 - with Alexco:** Scenario A1 plus Alexco load.

Table C-1 below summarizes Integrated Gird load scenarios for 2013-2030 years.

[4] In July 2013 Alexco Resource Corp. announced that it will close Bellekeno mine for winter and will reopen in spring of 2014 assuming the silver market has improved. Although the project could reopen in 2014, there is no current basis for addressing a 2014 forecast update - and the time of reopening of the mine is very uncertain. To address this uncertainty, two separate cases were prepared for the Base Case with and without Alexco. The case with Alexco assumes mine re-opening in 2015.

[5] On December 5, 2013 Alexco announced a strategy to initiate development of the Flame & Moth mine in 2014 as a first step to achieving commercial production from this deposit in 2015; recommissioning of the Bellekeno mine would begin later in 2014 so that this mine would be ready to simultaneously go into production along with Flame & Moth near the beginning of 2015. The current grid load update has not attempted to assess Alexco loads specific to this recent announcement.

[6] Scenario A1 assumes no Victoria Gold compared to Scenario A in March 2013 update, which included Victoria Gold mine. Victoria Gold received its Quartz Mining Licence for the Eagle Gold Project in September 2013; however, the timing for development is uncertain due to financial market conditions (2016 is the current stated focus to start production).

[7] Carmacks Copper has recently re-started its regulatory review processes, with an announced filing of a revised application planned this year or early 2014 with YESAB, followed shortly thereafter with revised filing with the YWB. PPA discussions occurred in the past – Carmacks Copper will be required to pay all costs required for grid connection plus a contribution to CSTP capital costs. The timing for connection of this mine remains uncertain, but could potentially occur by Q1 2018.

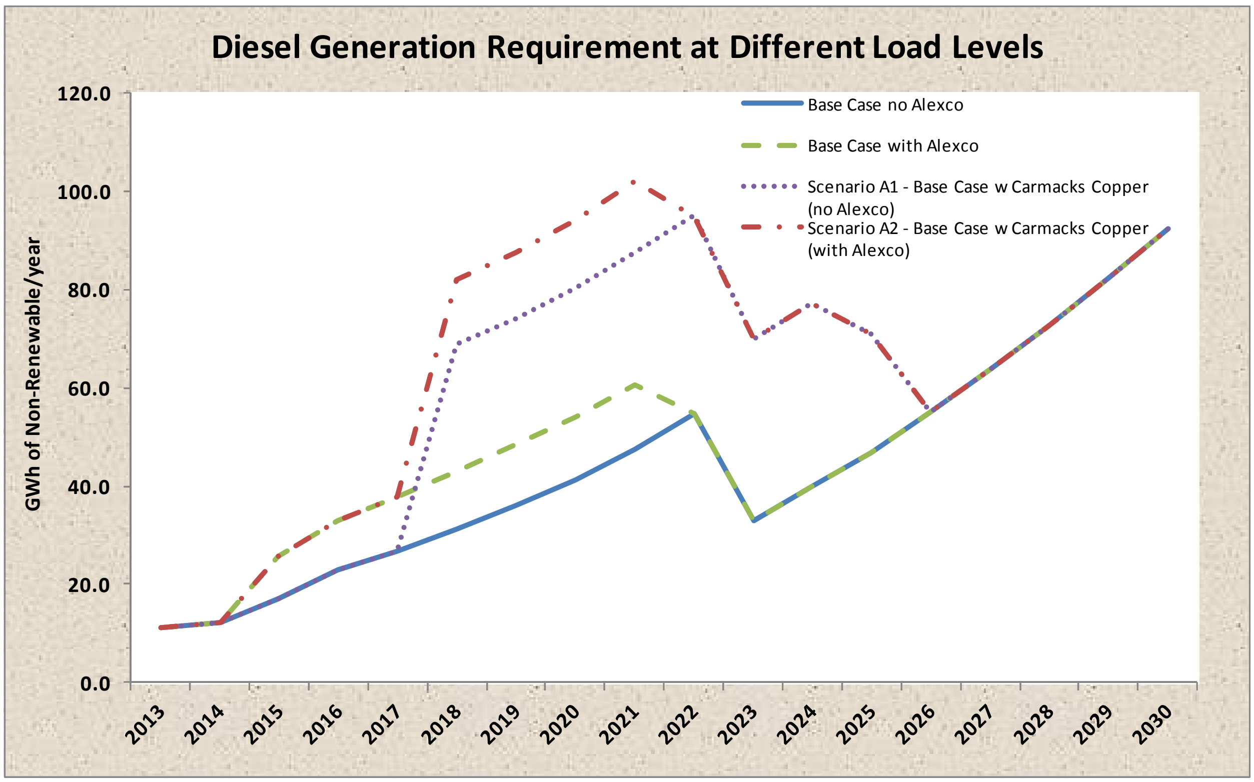
Table C-1: Updated Grid Load Scenarios

Forecast Years	Base Case no Alexco			Base Case with Alexco			Scenario A1 - Base Case w Carmacks Copper (no Alexco)			Scenario A2 - Base Case w Carmacks Copper (with Alexco)			Non-Industrial DSM/SSE (GW.h)
	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	
2013	369.9	43.5	413.4	369.9	43.5	413.4	369.9	43.5	413.4	369.9	43.5	413.4	0.0
2014	377.9	38.0	416.0	377.9	38.0	416.0	377.9	38.0	416.0	377.9	38.0	416.0	0.0
2015	386.1	40.2	426.3	386.1	55.4	441.5	386.1	40.2	426.3	386.1	55.4	441.5	0.6
2016	393.9	43.5	437.3	393.9	60.9	454.7	393.9	43.5	437.3	393.9	60.9	454.7	2.5
2017	400.9	43.5	444.3	400.9	60.9	461.7	400.9	43.5	444.3	400.9	60.9	461.7	5.4
2018	408.0	43.5	451.5	408.0	60.9	468.9	408.0	97.8	505.9	408.0	115.2	523.3	8.4
2019	415.4	43.5	458.9	415.4	60.9	476.3	415.4	97.8	513.2	415.4	115.2	530.6	11.5
2020	422.9	43.5	466.4	422.9	60.9	483.8	422.9	97.8	520.7	422.9	115.2	538.1	14.6
2021	431.8	43.5	475.3	431.8	60.9	492.7	431.8	97.8	529.6	431.8	115.2	547.0	18.4
2022	441.0	43.5	484.4	441.0	43.5	484.4	441.0	97.8	538.8	441.0	97.8	538.8	22.2
2023	450.4		450.4	450.4		450.4	450.4	54.4	504.7	450.4	54.4	504.7	26.1
2024	460.0		460.0	460.0		460.0	460.0	54.4	514.4	460.0	54.4	514.4	30.1
2025	470.0		470.0	470.0		470.0	470.0	27.0	496.9	470.0	27.0	496.9	34.3
2026	481.3		481.3	481.3		481.3	481.3		481.3	481.3		481.3	39.0
2027	493.0		493.0	493.0		493.0	493.0		493.0	493.0		493.0	43.9
2028	505.1		505.1	505.1		505.1	505.1		505.1	505.1		505.1	48.9
2029	517.6		517.6	517.6		517.6	517.6		517.6	517.6		517.6	54.1
2030	530.4		530.4	530.4		530.4	530.4		530.4	530.4		530.4	59.5

Figure C-1 and Table C-2 provide the forecast diesel generation requirement during the 20-year planning period for each of the load scenarios, assuming no new non-diesel generation resources.

1. The forecast diesel generation for each scenario is based on updated load for 2013-2030 (Table A-1), and long-term average (LTA) diesel requirements as reviewed below. Actual diesel requirements in any year will be affected by actual water and weather conditions.
2. LTA YECSIM model run with Aishihik 10-year rolling average rule, and no new renewable resources[8]. Potential displacement of diesel by natural gas (LNG) is not considered.

Figure C-1: Diesel Generation Requirements at Different Forecast Loads: 2013-2030



Diesel generation forecasts for each load scenario reflect long-term average hydro generation, i.e., the average hydro generation over 28 to 31 recorded water year conditions[9] at the assumed load, as estimated by the power benefits model used by YEC for grid generation planning.

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[8] For example, excludes Mayo Lake, Marsh Lake, or other new hydro enhancement or other renewable energy projects. The earliest potential timing currently estimated for securing new hydro generation benefits from the Mayo Lake Project is winter 2015/16 (thermal energy savings in 2016), and from the Marsh Lake project is winter 2016/17 (thermal energy savings in 2017). The combined impact of both projects would likely reduce long-term average diesel generation by approximately 10 GW.h/year.

[9] The long-term average (LTA) diesel generation estimates for 2013 and 2014 years are based on YECSIM-based table used for the approved 2012 GRA diesel generation forecasts, which uses 28 recorded water year conditions through to 2008, Aishihik 10-year rolling average for 1999-2008, and Mayo Lake rating curve based on licence conditions assuming no outlet channel constraints. The diesel generation estimates for 2015 and beyond are based on YECSIM power benefits model runs with updated recorded water year conditions for 2001-2011, Aishihik 10-year rolling average for 2002-2011, and Mayo Lake rating curve based on Mayo Lake

Table C-2: Long-Term Average Diesel Generation at Different Forecast Loads: 2013-2030

Forecast Years	Base Case no Alexco		Base Case with Alexco		Scenario A1 - Base Case w Carmacks Copper (no Alexco)		Scenario A2 - Base Case w Carmacks Copper (with Alexco)	
	Total Generation (GW.h)	Diesel (GW.h)	Total Generation (GW.h)	Diesel (GW.h)	Total Generation (GW.h)	Diesel (GW.h)	Total Generation (GW.h)	Diesel (GW.h)
2013	413.4	11.2	413.4	11.2	413.4	11.2	413.4	11.2
2014	416.0	12.3	416.0	12.3	416.0	12.3	416.0	12.3
2015	426.3	17.0	441.5	25.7	426.3	17.0	441.5	25.7
2016	437.3	22.9	454.7	33.1	437.3	22.9	454.7	33.1
2017	444.3	26.9	461.7	37.6	444.3	26.9	461.7	37.6
2018	451.5	31.4	468.9	42.8	505.9	68.9	523.3	81.8
2019	458.9	36.1	476.3	48.3	513.2	74.1	530.6	87.6
2020	466.4	41.1	483.8	54.0	520.7	80.1	538.1	94.2
2021	475.3	47.4	492.7	60.7	529.6	87.5	547.0	102.2
2022	484.4	54.7	484.4	54.7	538.8	95.2	538.8	94.8
2023	450.4	33.1	450.4	33.1	504.7	69.8	504.7	69.8
2024	460.0	39.8	460.0	39.8	514.4	77.2	514.4	77.2
2025	470.0	46.8	470.0	46.8	496.9	71.0	496.9	71.0
2026	481.3	55.0	481.3	55.0	481.3	55.0	481.3	55.0
2027	493.0	63.6	493.0	63.6	493.0	63.6	493.0	63.6
2028	505.1	72.7	505.1	72.7	505.1	72.7	505.1	72.7
2029	517.6	82.3	517.6	82.3	517.6	82.3	517.6	82.3
2030	530.4	92.5	530.4	92.5	530.4	92.5	530.4	92.5

Table C-3 and Figure C-2 review potential diesel generation variability for the year 2016 under Base Case loads and for the year 2018 under Scenario A loads for each of the 31 water years:

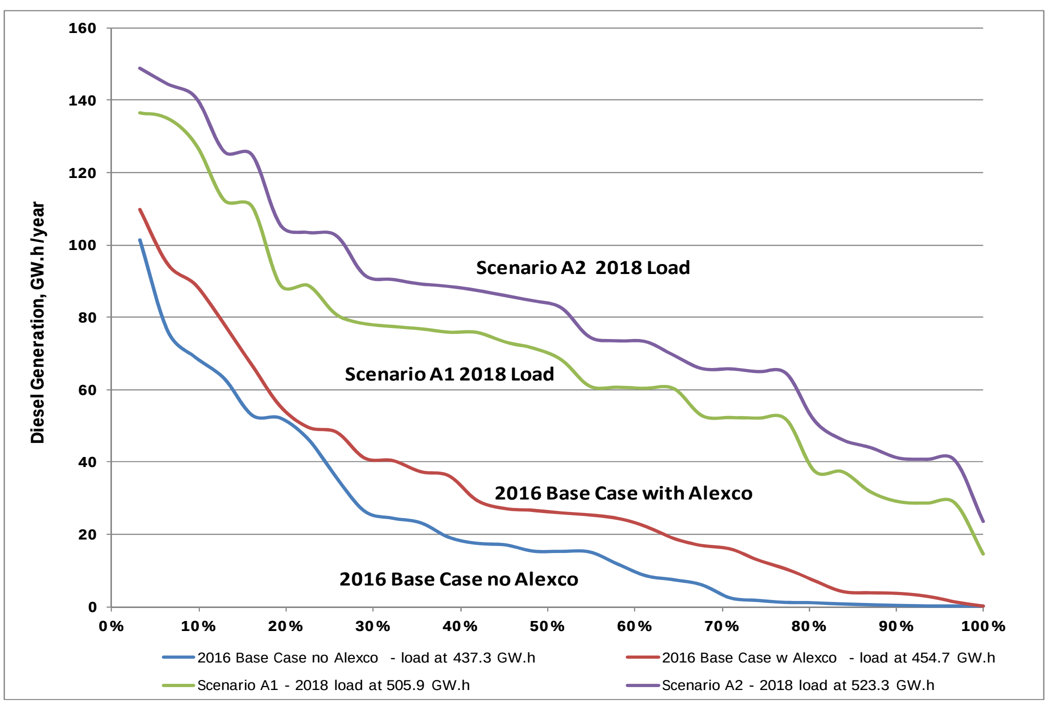
- The left side of Table C-3 shows, for the load in the stated year and load scenario, the annual variability of average diesel generation for each of the 31 water years of record (1981-2011); in each scenario, 1995 to 2000 is a string of six consecutive notable drought condition years. At the bottom of each scenario the long-term average (LTA) annual diesel generation is shown, based on the overall average for the 31 water years (same as shown in Table C-2).
- The right side of Table C-3 shows, for load in the stated year and load scenario, the percent of the 31 water years (i.e., how many years of the 31 years) when the annual average diesel generation required is not less than specified level.
- Figure C-2 shows the annual load duration curve for diesel generation over the 31 water years for each load scenario (reflects right side of Table C-3).

outlet channel existing conditions (recent study by KGS shows that sediments in Mayo Lake outlet channel from over 50 year operation constrains water flow through channel at low lake levels).

Table C-3: Forecast Diesel Generation Variability (GW.h) Depending on Water Year Conditions - Load Scenarios for 2016/2018 and 31 Water Years of Record

	Average diesel generation required (GW.h)				Distribution of Annual Water Year Loads					
Water Year	2016 Base Case no Alexco - load at 437.3 GW.h	2016 Base Case w Alexco - load at 454.7 GW.h	Scenario A1 - 2018 load at 505.9 GW.h	Scenario A2 - 2018 load at 523.3 GW.h		% of Years not less than	2016 Base Case no Alexco - load at 437.3 GW.h	2016 Base Case w Alexco - load at 454.7 GW.h	Scenario A1 - 2018 load at 505.9 GW.h	Scenario A2 - 2018 load at 523.3 GW.h
1981	0.1	4.2	28.9	41.2	1	3%	101.4	109.9	136.5	148.8
1982	1.6	10.4	68.2	84.6	2	6%	76.1	94.7	135.0	144.3
1983	0.3	22.2	60.2	73.3	3	10%	68.8	88.9	127.7	140.6
1984	5.9	49.6	88.9	102.5	4	13%	63.1	78.1	112.4	125.7
1985	24.4	41.1	75.8	88.6	5	16%	52.8	66.8	110.5	124.8
1986	46.2	40.4	73.1	86.0	6	19%	52.1	55.4	88.9	105.5
1987	11.7	16.9	51.6	65.0	7	23%	46.2	49.6	88.7	103.4
1988	15.2	24.5	52.2	64.5	8	26%	35.6	48.3	80.7	102.5
1989	2.3	7.2	31.6	44.1	9	29%	26.3	41.1	78.2	91.7
1990	1.1	12.9	52.1	65.9	10	32%	24.4	40.4	77.4	90.5
1991	0.3	2.9	37.4	51.5	11	35%	23.1	37.3	76.8	89.2
1992	0.1	0.2	14.5	23.7	12	39%	19.1	36.2	75.8	88.6
1993	0.6	1.3	28.6	40.9	13	42%	17.4	29.4	75.8	87.5
1994	0.1	3.7	80.7	103.4	14	45%	17.0	27.1	73.1	86.0
1995	35.6	78.1	127.7	140.6	15	48%	15.3	26.7	71.4	84.6
1996	63.1	94.7	135.0	148.8	16	52%	15.2	25.9	68.2	82.6
1997	68.8	88.9	112.4	124.8	17	55%	15.0	25.4	60.9	74.6
1998	76.1	66.8	110.5	125.7	18	58%	11.7	24.5	60.6	73.5
1999	101.4	109.9	136.5	144.3	19	61%	8.5	22.2	60.4	73.3
2000	52.8	48.3	76.8	89.2	20	65%	7.3	18.9	60.2	69.5
2001	23.1	16.0	37.2	46.2	21	68%	5.9	16.9	52.7	65.9
2002	26.3	27.1	52.7	65.8	22	71%	2.3	16.0	52.2	65.8
2003	15.0	29.4	75.8	87.5	23	74%	1.6	12.9	52.1	65.0
2004	52.1	55.4	88.7	105.5	24	77%	1.1	10.4	51.6	64.5
2005	19.1	25.9	77.4	90.5	25	81%	1.0	7.2	37.4	51.5
2006	15.3	37.3	78.2	91.7	26	84%	0.6	4.2	37.2	46.2
2007	17.0	36.2	60.6	73.5	27	87%	0.3	3.9	31.6	44.1
2008	17.4	25.4	60.4	69.5	28	90%	0.3	3.7	28.9	41.2
2009	1.0	3.9	28.6	40.5	29	94%	0.1	2.9	28.6	40.9
2010	8.5	18.9	60.9	74.6	30	97%	0.1	1.3	28.6	40.5
2011	7.3	26.7	71.4	82.6	31	100%	0.1	0.2	14.5	23.7
Average	22.9	33.1	68.9	81.8			22.9	33.1	68.9	81.8

Figure C-2: Duration Curve – Required Diesel Generation Hydro Grid Annual Water Variability



Projected annual grid capacity MW surplus (shortfall) under each load scenario is provided in Table C-4, assuming existing plant and planned diesel unit retirements and applying YEC's approved N-1 and LOLE capacity planning criteria[10]. Assumed diesel unit retirements as set out in the 2011 Resource Plan[11] are reviewed below, using projected shortfalls under the Base Case[12] to demonstrate the impact of assumed retirements:

- 2015 Base Case shortfall of 7.0 MW: reflects following 8 MW of diesel unit retirements:
    - Mirrlees WD#1 and WD#2 retired in 2014/2015 (2011 Resource Plan rating of 3.50 and 4.5 MW=8 MW total). [Unit capacities for these units and all other units included in this analysis reflect current de-rated status where relevant; rated capacity for WD#1 and WD#2=9.07 MW].
    - Replacing of these units with at least the same capacity would resolve the 2015 shortfall.
- 2020 Base Case shortfall of 20.7 MW: reflects following 14.31 MW of diesel unit retirements:
    - The above Mirrlees retirements (8 MW) plus.
    - Dawson retirement of 3 units (total 2.56 MW retired in 2017, 2018 and 2020).
    - Mayo retirement of 2 units (total 1.7 MW in 2019).
    - Faro retirement of 2 units (2.05 MW in 2019 and 2020).
- 2025 Base Case shortfall of 45.6 MW: reflects following 29.81 MW of diesel unit retirements:
    - The above 14.31 MW retired by 2020 plus.
    - Whitehorse retirement of 4 units (total 11.5 MW - last Mirrlees (4.5 MW) and 3 EMDs).
    - Faro Mirrlees unit (4.0 MW in 2021).
- 2030 Base Case shortfall of 63.6 MW: reflects following 35.61 MW of diesel unit retirements:
    - The above 29.81 MW retired by 2025 plus.
    - Whitehorse CAT (3.0 MW in 2026).
    - Faro CAT (2.8 MW in 2027).

[10] The N-1 capacity planning criteria focuses only on non-industrial peak load during winter (i.e., industrial peak load is excluded), and hydro generation firm capacity during winter. The N-1 event assumes loss of the Aishihik transmission line, i.e., all generation capacity at Aishihik (37 MW) and at Haines Junction (1.75 MW) is assumed not to be available to meet grid peak load excluding Haines Junction load (approximately 1 MW). Estimated shortfalls reflect re-enforcing of L172 currently being undertaken.

[11] Current integrated grid generating unit capacities and expected retirement dates are set out in Table 2-3 of the Yukon Energy 20-Yeart Resource Plan: 2011-2030 (December 2011). All YEC diesel units are expected to be retired by 2030 other than a 1.40 MW CAT at Dawson (expected to be retired in 2031).

[12] For both with and without Alexco cases under N-1 capacity requirement. YEC's 2011 Resource Plan update estimated that under the updated assessments Loss of Load Expectation [LOLE] affects planning requirements when industrial loads exceed 13 MW. Under Base Case scenario total industrial peak load is forecast to be below 13 MW [Minto at 5.3 MW and Alexco at 2.7 MW].

Table C-4: Grid Capacity Planning - Forecast MW Surplus (Shortfall) by Load Scenario: 2013-2030

Forecast Years	Base Case no Alexco			Base Case with Alexco			Scenario A1 - Base Case w Carmacks Copper (no Alexco)			Scenario A2 - Base Case w Carmacks Copper (with Alexco)		
	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)
2013	81.0	4.6	4.6	73.8	4.6	4.6	73.8	4.6	4.6	73.8	4.6	4.6
2014	80.6	-0.8	-0.8	80.6	-0.8	-0.8	80.6	-0.8	-0.8	80.6	-0.8	-0.8
2015	82.8	-7.0	-7.0	85.4	-7.0	-7.0	82.8	-7.0	-7.0	85.4	-7.0	-7.0
2016	84.3	-8.5	-8.5	87.0	-8.5	-8.5	84.3	-8.5	-8.5	87.0	-8.5	-8.5
2017	85.7	-10.9	-10.9	88.4	-10.9	-10.9	85.7	-10.9	-10.9	88.4	-10.9	-10.9
2018	87.2	-13.0	-13.0	89.8	-13.0	-13.0	94.4	-13.0	-13.0	97.1	-13.0	-15.3
2019	88.6	-17.0	-17.0	91.3	-17.0	-17.0	95.9	-17.0	-17.0	98.6	-17.0	-19.3
2020	90.2	-20.7	-20.7	92.8	-20.7	-20.7	97.4	-20.7	-20.7	100.1	-20.7	-22.9
2021	91.9	-31.0	-31.0	94.6	-31.0	-31.0	99.2	-31.0	-31.0	101.9	-31.0	-33.2
2022	93.8	-32.8	-32.8	93.8	-32.8	-32.8	101.1	-32.8	-32.8	101.1	-32.8	-32.8
2023	90.4	-34.7	-34.7	90.4	-34.7	-34.7	97.6	-34.7	-34.7	97.6	-34.7	-34.7
2024	92.3	-36.6	-36.6	92.3	-36.6	-36.6	99.6	-36.6	-36.6	99.6	-36.6	-36.6
2025	94.3	-45.6	-45.6	94.3	-45.6	-45.6	101.6	-45.6	-45.6	101.6	-45.6	-45.6
2026	96.6	-50.9	-50.9	96.6	-50.9	-50.9	96.6	-50.9	-50.9	96.6	-50.9	-50.9
2027	98.9	-56.1	-56.1	98.9	-56.1	-56.1	98.9	-56.1	-56.1	98.9	-56.1	-56.1
2028	101.3	-58.5	-58.5	101.3	-58.5	-58.5	101.3	-58.5	-58.5	101.3	-58.5	-58.5
2029	103.8	-61.0	-61.0	103.8	-61.0	-61.0	103.8	-61.0	-61.0	103.8	-61.0	-61.0
2030	106.4	-63.6	-63.6	106.4	-63.6	-63.6	106.4	-63.6	-63.6	106.4	-63.6	-63.6

Notes:

1. Non-industrial peak numbers for 2014-2030 are calculated based on YEC's three year average non-industrial load factor (2011-2013).
2. Minto at 4.8 MW in 2014, increasing to 5.3 in 2015 and shut-down in 2022; the cases with Alexco assume 2.7 MW load for 2015-2021; Carmacks Copper assumed at 7.3 MW.
3. Yukon Grid installed winter firm capacity at 114.49 MW by end of 2013 excluding Fish Lake Hydro and Haines Junction diesel. Total retirements are at 35.6 MW over 2014-2030.
4. The N-1 event assumes loss of the Aishihik transmission line, i.e., all generation capacity at Aishihik (37 MW) and at Haines Junction (1.75 MW) is assumed not to be available to meet grid peak load excluding Haines Junction load (approximately 1 MW).

APPENDIX D

LNG CAPACITY DIESEL DISPLACEMENT ASSESSEMENTS

Table D-1: Diesel Displacement Benefits of LNG Plant – Load for 2015, Base Case no Alexco

LNG Plant (Capacity Factor=0.91)	LNG Year Round Operation - Base Case						Drought Water Years Diesel Generation (GW.h/yr)									# of yrs with Diesel Gen-n Greater than 5 GW.h
	Energy (GW.h/yr)			Remaining LTA Diesel Generation	Incremental Diesel Reduction (%)	Total Diesel Reduction (%)	Highest Annual Diesel		Drought Water year sequence (averaged by WY)					Highest Weekly Diesel		
	Total	Displacing Diesel	Displacing Hydro				Before Averaging	After Averaging	1995	1996	1997	1998	1999	GW.h/ week	MW	
	A=B+C	**B**	**C**	**D=17.2-B**	**E=chD/chA**	**F=B/17.2**	**G**	**H=Max(I-M)**	**I**	**J**	**K**	**L**	**M**	**N**	**O=N/168*1000**	**P (out of 31)**
W/o LNG Plant				17.2			110.8	106.3	15.0	58.0	59.5	40.7	106.3	6.0	35.5	16
1 MW LNG Plant	8.0	3.1 *38%*	4.9 *62%*	14.1	38%	18%	105.4	101.8	3.7	53.4	54.3	34.9	101.8	5.7	34.0	13
2 MW LNG Plant	15.9	5.5 *34%*	10.5 *66%*	11.7	30%	32%	100.1	97.0	0.0	42.6	49.2	23.1	97.0	5.6	33.1	13
3 MW LNG Plant	23.9	8.3 *35%*	15.6 *65%*	8.9	35%	48%	94.8	85.4	0.0	28.3	44.1	14.2	85.4	5.4	32.3	8
4 MW LNG Plant	31.9	10.9 *34%*	21.0 *66%*	6.3	32%	63%	89.9	71.7	0.0	14.2	39.1	8.0	71.7	5.2	31.1	8
5 MW LNG Plant	39.9	12.9 *32%*	27.0 *68%*	4.3	25%	75%	71.9	66.0	0.0	0.5	34.6	1.7	66.0	5.1	30.2	5
6 MW LNG Plant	47.8	14.6 *31%*	33.2 *69%*	2.6	22%	85%	72.4	57.7	0.0	0.0	16.8	0.3	57.7	4.4	26.4	3
7 MW LNG Plant	55.8	15.7 *28%*	40.1 *72%*	1.5	13%	91%	45.6	45.6	0.0	0.0	0.0	0.2	45.6	4.3	25.5	1
8 MW LNG Plant	63.8	16.6 *26%*	47.2 *74%*	0.6	11%	97%	18.3	18.3	0.0	0.0	0.0	0.1	18.3	3.5	20.9	1
9 MW LNG Plant	71.7	17.2 *24%*	54.5 *76%*	0.0	7%	100%	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.5	0

Notes:
1. LNG plant assumed with year round operation at 97% capacity factor in winter months (weeks 1-20, 46-52) and 84.5% capacity factor in summer months (weeks 21-45), annual average capacity factor is 91%.
2. Numbers are based on YECSIM model version with updates (water years, Mayo Lake outlet channel rating curve, Aishihik rolling average). Assumes no Mayo Lake license change impact and no other new renewable generations.
3. Numbers in column D are long-term averages (average of 31 water years [1981-2011] and 13 load years).
4. Numbers in column G are highest annual diesel generation out of 403 data points (31 water years and 13 load years).
5. Numbers in columns I-M are averaged annual diesel generations by load years.
6. Numbers in column N are highest weekly diesel generation (highest out of 20,956 data points = 31 water years, 13 load years and 52 weeks).
7. Numbers in column O are calculated based on numbers in column N divided by 168 hrs in a week.
8. The load forecast is based on November 30, 2013 update. Load shape for the run is based on 2014 BP non-industrial plus industrial load.

Table D-2: Diesel Displacement Benefits of LNG Plant – Load for 2016 and 2017, Base Case no Alexco

LNG Plant (Capacity Factor=0.91)	LNG Year Round Operation - Base Case						Drought Water Years Diesel Generation (GW.h/yr)									# of yrs with Diesel Gen-n Greater than 5 GW.h
	Energy (GW.h/yr)			Remaining LTA Diesel Generation	Incremental Diesel Reduction (%)	Total Diesel Reduction (%)	Highest Annual Diesel		Drought Water year sequence (averaged by WY)					Highest Weekly Diesel		
	Total	Displacing Diesel	Displacing Hydro				Before Averaging	After Averaging	1995	1996	1997	1998	1999	GW.h/ week	MW	
	A=B+C	**B**	**C**	**D=Diesel-B**	**E=chD/chA**	**F=B/Diesel**	**G**	**H=Max(I-M)**	**I**	**J**	**K**	**L**	**M**	**N**	**O=N/168*1000**	**P (out of 31)**
Load at 437.3 GW.h/2016																
W/o LNG Plant				22.9			119.2	101.4	35.6	63.1	68.8	76.1	101.4	6.3	37.2	21
7 MW LNG Plant	55.8	19.6 *35%*	36.2 *65%*	3.3	35%	86%	75.4	62.1	0.0	0.0	25.3	0.3	62.1	4.5	26.8	4
8 MW LNG Plant	63.8	20.9 *33%*	42.9 *67%*	2.0	16%	91%	54.3	51.3	0.0	0.0	7.3	0.2	51.3	4.3	25.9	2
9 MW LNG Plant	71.7	21.9 *31%*	49.9 *69%*	1.0	12%	96%	31.1	31.1	0.0	0.0	0.0	0.2	31.1	4.2	24.9	1
10 MW LNG Plant	79.7	22.8 *29%*	57.0 *71%*	0.1	11%	99%	4.1	4.1	0.0	0.0	0.0	0.1	4.1	2.2	13.4	0
11 MW LNG Plant	87.7	22.9 *26%*	64.8 *74%*	0.0	2%	100%	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.5	0
Load at 444.3 GW.h/2017																
W/o LNG Plant				27.0			124.0	103.8	52.7	76.8	81.6	72.3	103.8	6.4	38.3	21
7 MW LNG Plant	55.8	21.8 *39%*	34.0 *61%*	5.1	39%	81%	86.8	68.2	0.0	6.2	36.4	5.1	68.2	5.2	31.0	8
8 MW LNG Plant	63.8	23.8 *37%*	40.0 *63%*	3.2	25%	88%	76.4	61.5	0.0	0.0	24.3	0.3	61.5	4.5	26.7	4
9 MW LNG Plant	71.7	25.1 *35%*	46.7 *65%*	1.9	16%	93%	52.5	50.6	0.0	0.0	6.4	0.2	50.6	4.3	25.8	2
10 MW LNG Plant	79.7	26.0 *33%*	53.7 *67%*	1.0	12%	96%	29.3	29.3	0.0	0.0	0.0	0.2	29.3	4.2	24.8	1
11 MW LNG Plant	87.7	26.9 *31%*	60.8 *69%*	0.1	11%	100%	2.4	2.4	0.0	0.0	0.0	0.1	2.4	1.8	10.5	0
12 MW LNG Plant	95.7	27.0 *28%*	68.7 *72%*	0.0	1%	100%	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.5	0

Notes:
1. LNG plant assumed with year round operation at 97% capacity factor in winter months (weeks 1-20, 46-52) and 84.5% capacity factor in summer months (weeks 21-45), annual average capacity factor is 91%.
2. Numbers are based on YECSIM model version with updates (water years, Mayo Lake outlet channel rating curve, Aishihik rolling average). Assumes no Mayo Lake license change impact and no other new renewable generations.
3. Numbers in column D are long-term averages (average of 31 water years [1981-2011] and 13 load years).
4. Numbers in column G are highest annual diesel generation out of 403 data points (31 water years and 13 load years).
5. Numbers in columns I-M are averaged annual diesel generations by load years.
6. Numbers in column N are highest weekly diesel generation (highest out of 20,956 data points = 31 water years, 13 load years and 52 weeks).
7. Numbers in column O are calculated based on numbers in column N divided by 168 hrs in a week.
8. The load forecast is based on November 30, 2013 update. Load shape for the run is based on 2014 BP non-industrial plus industrial load.