LNG TRANSITION OPTION

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INTRODUCTION

Liquefied natural gas (LNG) is a transition fuel option for Yukon. In the near term, LNG retains flexibility and diversity for energy use opportunities (e.g., for electricity generation locations and for end use sectors such as transportation) similar to that provided today by diesel fuel, but with reduced costs and reduced GHG emissions and air pollutants. In the longer-term, LNG facilitates planning for, and pursuit of, cost effective and environmentally responsible hydro or other renewable legacy resource development to secure sustained and larger reductions in Yukon costs and GHG emissions as soon as economically feasible in the future.

BACKGROUND ON CURRENT LNG SUPPLY OPPORTUNITIES FOR YUKON

LNG is natural gas that is refrigerated and turns to a liquid at -162 degrees Celsius and at low pressure. It is a clear, colourless, odourless, non-toxic liquid. Natural gas is liquefied to reduce the volume in order to transport it more economically from locations with gas supply to locations with no gas pipeline supply. The ratio of volumes of gas to the liquid state is about 620:1.

Near-term supply of LNG in Yukon is facilitated by abundant natural gas supplies in BC and Alberta being used to develop LNG liquefier facilities that can supply cost competitive LNG by truck to Yukon at volumes sufficient to meet all projected Yukon incremental power requirements over the next 20+years. Longer-term development of natural gas supplies in Yukon (e.g., through the Alaska Highway Pipeline Project, Eagle Plain gas development, or any other source[1]) would allow direct access to natural gas in some Yukon locations plus development of local Yukon LNG liquefier facilities to supply LNG to other locations.

New opportunities to consider LNG as a major fuel option to displace oil products in Yukon reflect recent natural gas supply exceeding the demand in North America, which has driven gas prices to historically low levels relative to oil prices, and new shale gas supplies that are expected to contribute to ongoing low prices[2]. Uncertainty is noted about potential environmental issues regarding shale gas development as well as the timing of development of new shale gas reserves[3].

Opportunities today to develop LNG use in Yukon are still in the resource assessment stage. These opportunities are facilitated by major new LNG facility development currently planned in BC and Alberta (including facilities for LNG sale into higher priced Asian export markets). The business case for such new

[1] Proponents of the Alaska Pipeline Project provided a project schedule in September 2011 meetings in Alaska indicating first gas in 2020 and full gas in 2021, assuming an October 2012 FERC filing and project sanction before mid-2015. There is currently no timing or plan for development of Eagle Plain, but potential options may emerge tied to development of a major new load such as the Casino mine.

[2] BC Hydro's January 2011 Integrated Resource Plan natural gas price forecast notes that supply softness has driven gas prices to historically low levels; shale gas is expected to contribute to ongoing low prices although uncertainty about environmental issues and timing of development of new shale gas reserves means BC Hydro is considering different scenarios with relatively large price ranges. BC Hydro's High gas price scenario assumes prices around $10/MMBTU escalating to about $13/MMBTU by 2027 ($2010); assumes shale gas either cannot be developed due to environmental concerns or is very slow to develop. BC Hydro's Low gas price scenario assumes prices ($2010) around $4/MMBTU escalating to about $5.5/MMBTU by 2027. BC Hydro's Mid gas price scenario assumes prices ($2010) start around $4/MMBTU and escalate to about $7/MMBTU by about 2020 and about $7.5/MMBTU by 2027.

[3.] Production from shale gas that involves hydraulic fracturing has come under scrutiny due to environmental and health safety concerns relating to the potential contamination of surface or near-surface water supplies and other potential environmental impacts. Ongoing LNG export development in northern BC is one indication of market confidence that shale gas development will continue to sustain low North American natural gas prices relative to the price of oil.

LNG export confirms the expectation that it is profitable on a sustained basis (i.e., for the economic life of the new LNG facilities) to buy inexpensive gas in BC/Alberta indexed to lower 48 pipeline gas cost (Henry Hub and NYMEX), and cover the capital and operating costs for liquefying the gas to LNG and transporting the LNG to market by ship for sale at world export market prices. The expected sales margin (i.e., the difference in prices for gas between the North American and Asian markets) for such LNG exports confirms an expectation that natural gas prices in North America will remain significantly depressed relative to oil prices. The following are noted in regard to the development of specific LNG facilities in BC and Alberta:

- The BC Government has noted (see The BC Jobs Plan[4]) that LNG exports have the potential to replace coal-fired generation in China and other energy hungry countries, and that the BC Government is committed to working with LNG export proponents to bring at least one gas transmission pipeline and LNG terminal online by 2015 and have three in operation by 2020, assuming all environmental and permitting applications are granted.

- Kitimat LNG has announced plans to develop an LNG facility at Kitimat for operation in 2015 with an initial capacity of 32,000 m^3/day LNG (about 5 million metric tonnes per year) for marine transport by ship, i.e. by comparison, total future Yukon peak daily demand at all potential on and off grid locations after 2018 (including the Casino mine project) would be less than 10% of this export capacity by Kitimat LNG. The project is being developed by EnCana Corp. (30%), Apache Corp of Houston (40%) and EOG Resources Ltd., of Houston (30%), with an estimated project cost of $3.5 billion for the first train and $1.5 billion for an equivalent scale second train. Required federal and provincial approvals have been secured, including an NEB 20-year export licence granted in October, and a land lease has been arranged with the Haisla First Nation. Construction is planned to begin in the first quarter of 2012 and first LNG exports in 2015.

- BC LNG Export Co-operative has applied to the NEB for a 20 year export license for 1.8 million tonne LNG/year produced on a grounded barge at Kitimat starting in 2013[5]. The project is a 50/50 partnership between the LNG Partners (Houston) and the Haisla Nation Douglas Channel LNG Limited Partnership, and has arrangements to take advantage of unused capacity on the existing Pacific Northern Gas Pipeline.

- Royal Dutch Shell Plc is reported[6] to have filed for regulatory approval to build a small-scale LNG plant to produce 0.3 megatonnes per year at its existing Jumping Pound gas plant about 30 km west of Calgary. Work is expected to be completed by 2013. The project is to promote LNG as a transportation fuel (especially for trucks) in Alberta and eventually in BC.

- The Fort Nelson area in BC is recognised to have major gas reserves. A potential LNG facility developed today in this area could, for example, receive pipeline quality natural gas at high pressure from the send-out pipeline from the Spectra Energy's 250-MMcfd natural gas plant near

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[4] The BC Jobs Plan (http://www.bcjobsplan.ca/wp-content/uploads/2011/09/CSH_BCJobsPlan_web.pdf).

[5] The facility will be built on a barge off site and then floated to Kitimat. The front end engineering and design (FEED) contract was awarded in September 2011 for expected completion in January 2012.

[6] See Financial Post (Sept 7, 2011) http://business.financialpost.com/2011/09/07/shell-plans-alberta-lng-plant-to-supply-truck-fuel.

Fort Nelson[7], pre-treat the gas to remove unwanted components (primarily water and CO_2) and then refrigerate the clean gas to LNG for transportation and supply. Gas supplies for LNG production in the Fort Nelson area are expected to be indexed to lower 48 pipeline gas cost (Henry Hub and NYMEX), which are expected to be at least $3 MMBTU lower than Kitimat-based LNG production that will be indexed to world LNG prices.

CURRENT LNG SUPPLY OPTIONS FOR YUKON

Trucked-in LNG is assumed as the current near-term supply source of Yukon LNG until local natural gas supplies are available – for initial assessment, an LNG supply is assumed to be secured from facilities developed at Kitimat or at Fort Nelson, B.C., with the LNG then shipped to Whitehorse (for YEC grid power use), Watson Lake (for YECL utility generation) and potentially off grid mine sites (for generation at each mine site).

The March 2011 Energy Charrette noted that due to the isolated nature of the Yukon grid and the potential for large industrial loads to come on and off the system, resource planning must ensure supply options are sufficiently flexible and robust to address the markedly different load scenarios that may exist on the grid from time to time. Changes in load may adversely impact grid diesel generation requirements and related GHG emissions, as well as the cost effectiveness and rate impacts for any capital intensive supply options pursued in the near-term. Similarly, new capital intensive renewable resource developments may create new increases in supply that need to be accommodated concurrently with big swings in electrical load. Flexible and reliable supply options with low capital costs will also continue to play a key role on the Yukon hydro grid to address winter peak capacity as well as emergency reserve requirements, seasonal load/hydro supply fluctuations and annual hydro supply fluctuations.

Subject to securing LNG supply, LNG/Natural Gas is recognized as a reliable resource option for power generation that offers many of the same attributes as diesel generation, but at lower overall cost, GHG emissions and air pollutants than diesel. Key related features include:

- Natural gas power plants are intended to be operated only when required and (subject to securing fuel supply) can be relatively easily integrated into the Yukon system as conversion or replacement of the current diesel generation plant. New equipment and retrofit of existing diesel engines can provide a range of options for LNG/natural gas use, including options for dual fuel (diesel/natural gas) operation.

- Natural gas power plants require relatively low capital costs, with options for "scalable" generation over a wide range of sizes, as well as options for combined cycle and cogeneration (with associated higher capital costs).

[7] This plant is located about 75 km northeast of Fort Nelson, is the largest sour gas processing plant in North America and is the only facility currently processing Horn River gas. Spectra Energy has firm commitments of 760 MMcfd from seven producers operating in the Horn River basin for gathering and processing capacity, and may expand gathering and processing in this area to accommodate as much as 830 MMcfd of incremental gas from Horn River producers.

- Natural gas power plant operating costs are mostly composed of fuel cost that is subject to ongoing inflation and market price uncertainty, although natural gas prices in North America have tended to show more moderate swings than diesel prices.

- Natural gas power units can be permitted, purchased and installed within reasonably short time periods (i.e., usually well under 2 years) using proven technology that is readily available from multiple vendors and be reliably operated over an economic life of 20-25 years; units can also be located at load centres (minimize transmission requirements).

A gas co-generation facility installed in Whitehorse would also provide an opportunity for waste heat application, in much the same way (and for the same markets) as reviewed for biomass or waste-to-energy resource options.

LNG has been identified as the preferred energy source for the Casino project to reduce costs related to this mine's future large-scale baseload power generation[8], and the developer of the Northern Dancer mine[9] is also considering LNG as a source of supply. Use of LNG in a combined cycle power facility at the Casino project is expected to reduce costs at this mine site to within an 11-15 c/kWh range (versus the 30+ cent/kWh range for diesel). Under this approach, Casino (as well as Northern Dancer) would also retain flexibility to further reduce operating costs by converting the power generation to natural gas when/if local natural gas becomes available (e.g., power generation costs estimated for Casino at <10 c/kW.h with access to Alaska Highway Pipeline Project natural gas). Other mining developments in Yukon such as Wolverine and in north east BC such as Turnagain Nickel near Dease Lake could also benefit from access to LNG.

Based on the preliminary analysis to date, Yukon Energy has participated with Western Copper and Gold retaining Braemar Wavespec and Berger ABAM to evaluate the LNG & Natural Gas supply chain in lieu of diesel for electrical power generation fuel at the proposed Casino mine and process facility starting in 2019, and at Yukon Energy facilities at Whitehorse and YECL facilities at Watson Lake potentially starting in 2014 as well as at other off grid existing and potential mine facilities (Wolverine, Selwyn and Coffee Creek were assumed for this purpose). The Braemar Wavespec studies are considering potential LNG supply chain options to secure LNG by trucking from either the proposed Kitimat LNG new facility at Kitimat BC or from pipeline gas at Fort Nelson BC[10] to reduce costs and emissions in Yukon by using LNG to displace diesel generation. Preliminary conclusions from studies to date include the following (see Figure 1):

- Under assumed diesel and natural gas price conditions (e.g., LNG cost at $9/MMBTU at Kitimat, natural gas cost at $6/MMBTU at Fort Nelson, and diesel fuel cost at $26/MMBTU or 89 cents per

[8] The Casino mine developer (Western Copper and Gold) currently plans to secure LNG by truck and/or ship/truck from Kitimat or to secure LNG from a new LNG facility at Fort Nelson, BC. The Casino mine is expected to have a large scale power requirement starting in 2019 of 130 MW and 940 GW.h/year potentially sustained over several decades.

[9] With a power requirement of 30-35 MW (200 to 300 GWh/year) for up to 30 years, potentially starting by 2017.

[10] Braemar Wavespec also examined options for the Casino plant shipping LNG from Kitimat LNG by barge or small carrier to Skagway, Alaska and from there by truck to the mine site – based on review of this alternative, the studies related to other potential Yukon uses by Yukon Energy or others focused on the trucking option from either Kitimat LNG or from a new LNG facility using pipeline gas at Fort Nelson BC. An Eagle Plain option was also examined simply to assess potential future cost savings at such time as natural gas production is available from Eagle Plains.

litre), an LNG supply chain from either Kitimat or Fort Nelson is more cost effective than diesel for the various Yukon power generation use options and locations examined:

- At lower supply level requirements typical of utility diesel power generation requirements, including full consideration of grid diesel load fluctuations due to hydro generation seasonal and annual water flow fluctuations[11], LNG supply from Kitimat LNG tended to have better project economics for delivered LNG unit cost compared to Fort Nelson LNG (reflecting lower capital cost requirements for the option using an assumed Kitimat LNG export facility [rather than a new dedicated LNG liquefaction facility at Fort Nelson] offsetting longer truck distances and higher gas-equivalent prices).
  - Estimated unit grid power generation costs[12] with simple cycle generation ranged from 17.0 cents/KWh (Scenario A) to 15.7 cents/kWh (Scenario B) with supply from Kitimat - in contrast, with supply from Fort Nelson the estimated unit costs range from 17.9 cents/kWh (Scenario A) to 15.8 cents per kWh (Scenario B).
  - Estimated unit power generation cost with combined cycle generation was lower than with simple cycle generation (15.6 to 14.2 cents/kWh with Kitimat supply and 16.4 to 14.2 cents per kWh with Fort Nelson supply).
  - Capital cost requirements were lower with the Kitimat supply option than with the Fort Nelson supply option, e.g., for the assumed Scenario A grid plus Watson Lake diesel displacement loads and combined cycle power generation, estimated capital costs for the LNG supply chain (excluding costs for new generating units) ranged from approximately $13 million for the Kitimat option to approximately $37 million for the Fort Nelson option (of which liquefaction facility costs approximated $26 million).
- LNG supply chain economics improved if additional LNG deliveries for off grid mine power generation are assumed (beyond YEC and YECL loads assumed above). With the higher and more steady state load profile, Fort Nelson with new LNG facility costs dedicated only to Yukon loads has lower estimated delivered costs than LNG purchases from a Kitimat LNG export facility.
  - This conclusion applies with or without the Casino mine (although higher loads with the Casino mine tend to result in lower overall average supply chain costs per MMBTU than cases without the Casino mine load, notwithstanding impacts on increasing overall average trucking distance).
  - Combined cycle generation continues to offer cost savings compared to simple cycle generation.

- Overall, increases in the LNG supply chain load requirement act to maintain and improve supply chain economics; delivered unit cost with all users examined is lower than would occur with only

[11] To accommodate these factors, LNG supply chain peak capability for grid power use assumed in the Braemar Wavespec study at 25 MW for grid loads with Victoria Gold connection (Scenario A) and 30 MW for grid loads with an additional mine connection (Scenario B). At the assumed grid loads (84.9 GW.h/year for grid Scenario A and 142.9 GW.h/year for grid Scenario B), average annual grid use assumed at only 39% of capacity for Scenario A and 54% for Scenario B.

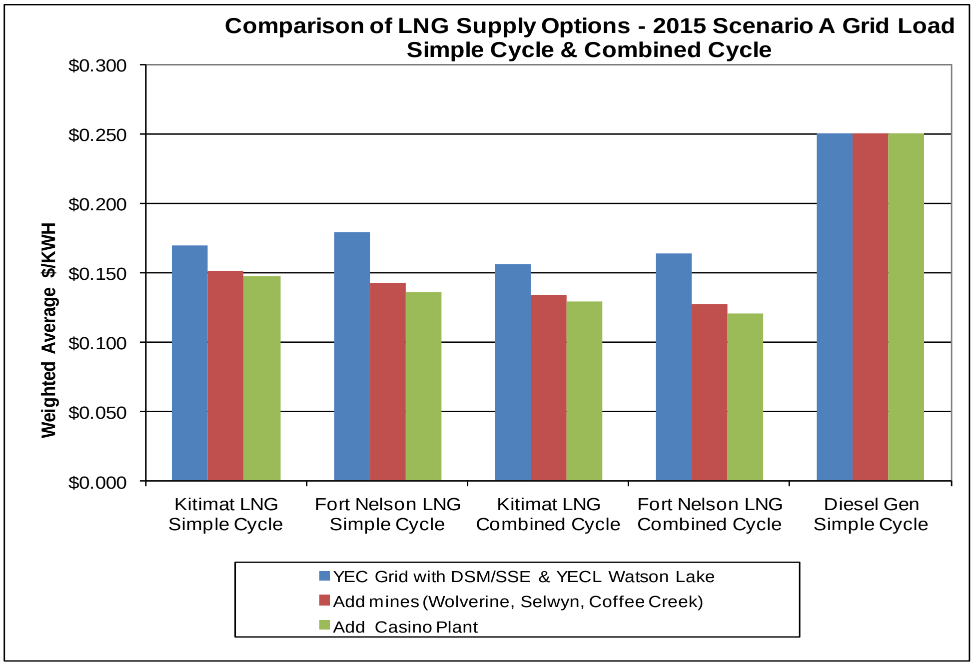
[12] All costs estimated assuming 8% annual cost of capital and 20 year economic life – annual costs reflect the assumed fuel prices and operation at current day dollars. The capital portion of these costs assumes 20 years of operation at the assumed loads.

utility grid and Watson Lake loads. With appropriate planning, supply chain additions are very scalable through addition of added trucking units and liquefaction trains. There are a number of processes for small and mid-sized LNG liquefiers from a number of vendors who produce turnkey solutions with proven technology.

- The cost of gas from Fort Nelson will likely sustain a lower unit cost than reliance on an LNG export facility at Kitimat overtime; trucking distances are also considerably reduced under the Fort Nelson supply option compared with the Kitimat supply option. Although not reviewed in detail, an Eagle Plain commercial gas supply would enable reduced LNG trucking distances on average for the Yukon loads considered.
- Due to the long LNG supply chain for all concepts, project risks need to be identified and examined for the real world challenges to provide the level of reliability and sustainability of energy supply needed.
- Potential optimization measures to address grid load seasonality and other annual hydro fluctuations include increased LNG receiving terminal storage, retaining some existing diesel generation capacity for peaking in lieu of requiring LNG supply chain design capacity for such peaking, and use of LNG fuelled power generation during non-winter months in low water years in order to facilitate hydro storage for winter use. Waste heat recovery from power generation provides an excellent source of free heat to displace fuel gas otherwise needed for LNG vaporization at receiving facilities (this is the largest operating expense for this operation), assuming a backup source of heat is available during short periods that waste heat is not available.
- Construction of the supply chain (including a liquefaction facility for the Fort Nelson option) will take at least 2 years including detailed engineering, permitting, construction, start-up and commissioning (excluding new power generators) - this schedule is based on having a site selected for the LNG supply, budgetary approval and no major problems with permitting.
    - When considering risks that natural gas supplies will emerge in Yukon and displace the need to transport LNG from BC, it is noted that the proposed LNG liquefaction equipment is modular, and relocation to another location (i.e., in Yukon) can be performed at relatively low cost compared to the cost of a new facility (and assuming production downtime during the relocation is also considered).
    - Assuming that off grid mine loads continue to develop, emergence of Yukon gas sources will likely not displace the ongoing need for LNG liquefaction in Yukon to supply off grid power generation as well as transport uses.

Subject to successful planning for power uses of LNG in Yukon, consideration will be given by Yukon Energy for a wider range of potential LNG end use sectors in Yukon (including transportation and heating sectors). The LNG supply chain examined by Braemar Wavespec assumes LNG-fuelled trucks.

Figure 1:
Comparison of LNG Supply Options (Kitimat & Fort Nelson) with Diesel



Weighted Av. $/kWh	Simple Cycle[1, 3, 4]			Combined Cycle[2, 3, 4]		
	Kitimat LNG[5]	Fort Nelson LNG[5]	Diesel Generation[5]	Kitimat LNG[5]	Fort Nelson LNG[5]	Diesel Generation[5]
Grid/ Watson Lake	$0.170	$0.179	$0.251	$0.156	$0.164	$0.251
Add Mines	$0.151	$0.143	$0.251	$0.134	$0.127	$0.251
Add Casino	$0.147	$0.136	$0.251	$0.130	$0.121	$0.251

Notes:
1. LNG generating with new units at $1,500 per kW capital cost (40% enrgy efficiency).
   Diesel generating with existing simple cycle units (no capital cost - same efficiency as LNG simple cycle unit).
2. LNG generating with new units at $1,830 per kW capital costs (50% energy efficiency).
   Diesel generating with existing simple cycle units (no capital cost - same efficiency as LNG simple cycle unit).
3. Power generation for all units assumes 1.5 cents/kWh O&M cost.
4. Annual costs of capital assume 8% discount rate and economic life of 20 years.
5. LNG cost at $9/ MMBTU; Natrual gas cost at $6/ MMBTU; Diesel fuel cost at $26/ MMBTU (89 cents/litre).

LNG TRANSITION OPTION IN YUKON

Looking beyond the next few years, there are a range of greenfield hydro resource project opportunities potentially available to start construction before 2021, subject to appropriate planning and development of loads sufficient to fully utilize these resources. These opportunities offer potential to establish sustainable lower cost electricity as well as low GHG emissions in a way similar to that secured by earlier legacy hydro developed in response to earlier major Yukon industrial mine developments. Near-term cost savings provided by a LNG Transition option could facilitate ability to proceed with such planning for the next major legacy renewable resource developments.

The LNG Transition option is a potential "transition" response to current grid load forecasts and the near-term impacts expected to be associated with the Default Diesel Portfolio as well as various renewable resource development options. LNG is not considered as a long-term legacy resource option for Yukon. The intent would remain to displace LNG use with appropriate renewable resource options when it is cost effective to do so, i.e., when sustained high utilization can be effectively achieved for renewable electricity generation options over most of their economic life so as to secure a forecast levelized cost of energy (LCOE) over an option's economic life that is equivalent to or less than LNG costs.

Development of such longer-term renewable resource options is subject to connecting new grid loads that could fully utilize the specific renewable resource options over 20-30 or more years. Protecting the option to start construction for such projects before 2021 is contingent upon sustaining sufficient site specific planning processes as required throughout the next five year period through 2015. Potential new off grid loads during the next decade offer the opportunity to plan on a coordinated basis for new legacy hydro or other renewable resource development opportunities concurrent with actual development of new major mines or other major new loads.

Focusing on the near-term regarding resource projects for potential commitment before 2015, the LNG Transition option provides a range of potential benefits relative to the other available near-term grid generation options:

- Where established, LNG would displace diesel as the default option in Yukon (although dual fuel units could also cost effectively retain flexibility to use diesel if and when that would be advantageous). Lower cost LNG fuel would affect the assessment of future resource choices and also incremental pricing and rate setting in the rate zones where it is utilized, i.e., run out rates for higher use levels could be set based on LNG costs rather than diesel fuel costs.
- Other potential development benefits include:
  - LNG can offer material reductions in near-term rate increase impacts under potential forecast grid loads, as well as the non-diesel option with the lowest rate impacts in the event that mine closures reduce grid loads after 2020.
  - LNG provides a cost effective contribution to grid capacity planning requirements, and the planned retirements of all of YEC's diesel plant over the 20-year planning period.
  - As a result of the above impacts, LNG offers the opportunity to reduce present value diesel costs during the planning period.
  - Overall, this option offers high flexibility, and ability to accommodate load changes; it can also be cost effectively developed concurrently with hydro enhancements such as Marsh Lake Storage and Gladstone Diversion.
  - The LNG Transition option can accommodate optimum timing for Gladstone diversion, other potential hydro enhancements or greenfield developments, and wind development in response to confirmation of longer-term grid loads needed to secure reduced Forecast LCOE for these various renewable resource options.

- LNG is the only portfolio option that can be used off grid to reduce reliance on diesel (i.e., off grid communities such as Watson Lake and mines at various off grid locations). This option can also be used to reduce GHG emissions in other sectors where GHG emissions impacts are more significant (e.g., transportation and open pit mining heavy mobile equipment).

In order to pursue the LNG option for near-term development for power generation in Yukon by late 2014, immediate further feasibility work is required to determine the optimum way to secure the LNG, the required timing and all related costs (including assessment of potential options for LNG supply chain development jointly with other interests to meet broader near and longer term Yukon opportunities). Feasibility work is also required to optimize the specific Yukon Energy generation capacity and technology for power generation using LNG (including assessment of the optimum combination of combined cycle and simple cycle units in response to different potential load scenarios).