

**YUKON  
ENERGY**



**YUKON ENERGY CORPORATION**

**OVERVIEW OF 20-YEAR RESOURCE PLAN: 2011-2030**

**July 2012**



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## **INTRODUCTION**

Yukon Energy's 2011 Resource Plan addresses generation and transmission priorities in Yukon for the 20-year planning period (2011-2030), focusing on:

- Resource options for implementation over the first five years (2011-2015); and
- Planning activities for implementation during the first five years to protect longer-term legacy resource development options for potential start of construction before or after 2021.

The 2011 Resource Plan updates the review of overall planning priorities and options as last provided in the 2006 Resource Plan. It was drafted in late 2011 based on then available information. Overall load forecasts and analysis of specific project options are subject to ongoing updates. As reviewed in the 2006 Resource Plan, several additional planning stages are required beyond the Resource Plan prior to any Yukon Energy decision to proceed with construction for any preferred project<sup>1</sup>.

The Overview summarizes the 2011 Resource Plan document. Where relevant, the Overview also notes more recent information that may modify the earlier analysis.

### **Background on 2011 Resource Plan Process**

The first activity Yukon Energy undertook preparing this latest 20-year resource plan was to seek input from First Nations and other governments, stakeholders and the public through meetings, workshops and a three-day energy planning charette held in March 2011.

The charette brought together Yukoners from all walks of life along with nationally and intentionally-recognized energy experts. Information and knowledge was shared and the participants provided a great deal of input in terms of what Yukon's energy future should look like.

Dr Mark Jaccard led off the proceedings by clarifying his experience regarding energy planning and urged participants to thoughtfully consider all of the choices available and to examine the alternatives from the point of view that all options have impacts and risks and all require trade-offs.

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<sup>1</sup> Subsequent planning stages include: the final feasibility assessment, costing, design and contract arrangements (and related tendering to obtain final estimated costs); consultation with First Nations and others; all required external reviews, approvals and agreements (includes where relevant YESAB, DFO, YWB and other regulatory authorities as required, as well as seeking YUB review of near-term projects over \$3 million).

Dr. Jaccard also talked to the gathering about how we determine and provide affordable energy:

- What role energy has in economic development;
- Future demand and supply; and
- The need to examine multiple objectives.

Along with providing a list of potential energy options that required further investigation and analysis, the charrette participants also helped Yukon Energy formulate four principles around which to base future energy decisions. They include:

- Reliability;
- Affordability;
- Flexibility; and
- Environmental Responsibility.

With these four principles as the lens through which all possible energy options were considered, Yukon Energy prepared later in 2011 a draft of a new 20-year resource plan that is summarized in this Overview for Yukoners to review.

Yukon Energy recognizes that the 2011 Resource Plan, as with its predecessor, is a living document that continues to evolve.

Yukon Energy has continued in fall 2011 and 2012 to date, for example, to hold workshops to examine in more detail specific resource options, including waste to energy, biomass, liquefied natural gas, and energy conservation. As noted in this Overview, new load forecast scenarios have also been developed since the draft 2011 Resource Plan to reflect updated information.

Yukon Energy will continue to use the draft 2011 Resource Plan to frame priorities and options for ongoing new assessments and analysis, without going back to amend or revise the draft as prepared in 2011.

All papers, reports, presentations and records from the energy charrette and workshops have been made available to the public on Yukon Energy's web site.

### **Outline of Overview**

The Overview summarizes the 2011 Resource Plan as follows:

- Current Challenges and Opportunities;
- Background on Yukon Power System;
- Future Yukon Power Requirements – Overview;
- Range of Resource Supply Options;
- Yukon Utilities – Default Diesel Portfolio Requirements;
- Near-Term Resource Options to Default Diesel;
- Longer-Term Resource Options to Default Diesel; and
- Summary Conclusions & Recommended Plans.

The Overview summarizes the 2011 Resource Plan as drafted in late 2011. Where relevant, the Overview also notes more recent information that may modify the earlier analysis. Updated load forecasts that Yukon Energy is currently using, for example, are provided in the Appendix A. Ongoing examination of specific resource options continues, using updated information and analysis as required.

Yukon Energy will review the Overview and draft 2011 Resource Plan with the public, and report on the results of this review, including any resulting adjustments to recommended plans for ongoing priority attention.

## **1.0 CURRENT CHALLENGES AND OPPORTUNITIES**

Unprecedented growth is expected in Yukon-wide electricity requirements over the next decade, creating new generation challenges:

- **Near-Term Challenges** – To move quickly to meet new grid energy requirements emerging today with options that cost materially less than diesel generation while continuing the planning needed to develop longer-term Yukon power resources.
- **Longer-Term Opportunities** – Development as soon as feasible in future of hydro and other Yukon power resources to supply growing Yukon loads with reduced costs and emissions.

The 2011 Resource Plan assesses resource options in the context of current forecasts for overall Yukon energy and capacity requirements (i.e., off-grid as well as on-grid for all major power loads), agreed upon resource planning principles<sup>2</sup>, and the assumption that Yukon Energy is proceeding with a robust and aggressive Demand Side Management/Supply Side Enhancement (DSM/SSE) program in response to Yukon Utilities Board Directives, government policy considerations and stakeholder comments.

Key challenges related to new generation requirements in Yukon include:

- **Higher Costs** – Higher costs to secure safe and reliable new resource supplies from utility operations on or off the grid will increase rates throughout Yukon. Electricity prices in Yukon today are relatively low due to legacy hydro. On Yukon's isolated grid, planning and capital costs are borne by ratepayers (no opportunity to 'overbuild' and sell to another market).
- **Higher Greenhouse Gas ("GHG") Emissions** – Higher GHG emissions from increased electricity generation in Yukon on and off the grid (including utility and non-utility operations) will challenge Yukon's ability to secure overall GHG emission reductions.
- **Flexibility Required** – The isolation of Yukon's electrical system requires flexibility to address a wide range of challenges, including: seasonal variations in loads and existing hydro generation; annual changes in grid hydro generation due to varying water conditions; development and/or shut down of major mine loads; and potential changes in competitive generation option costs due to new resource supplies becoming available (e.g., development of accessible natural gas in Yukon).

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<sup>2</sup> The four key planning principles agreed to by the March 2011 Energy Charrette participants are reliability, affordability, flexibility and environmental responsibility.

## **2.0 BACKGROUND ON YUKON POWER SYSTEM**

Yukon's centres continue to have residential and commercial electric rates that are lower than other northern centres in Canada, reflecting extensive reliance on low cost legacy hydro generation.

Figure 2-1 provides a map of existing power infrastructure, active and potential mine developments, the potential Alaska Highway Pipeline, and future power supply options in Yukon over the planning period. Areas within a 50 km boundary from the current and potential future electric grids are identified (based on the current southern highway structure).

Current and committed generation capacity in Yukon includes approximately 138 MW of installed generation on the integrated grid (approximately 92 MW YEC hydro, 0.8 MW YEC wind, 37 MW YEC diesel, 1.3 MW YECL hydro, and 6.8 MW of YECL diesel) and 8.4 MW of diesel generation in five separate off-grid diesel-served communities supplied by YECL (5.3 MW in Watson Lake, 2.0 MW in three Small Diesel zone communities along the Alaska Highway, and 1.1 MW in Old Crow).

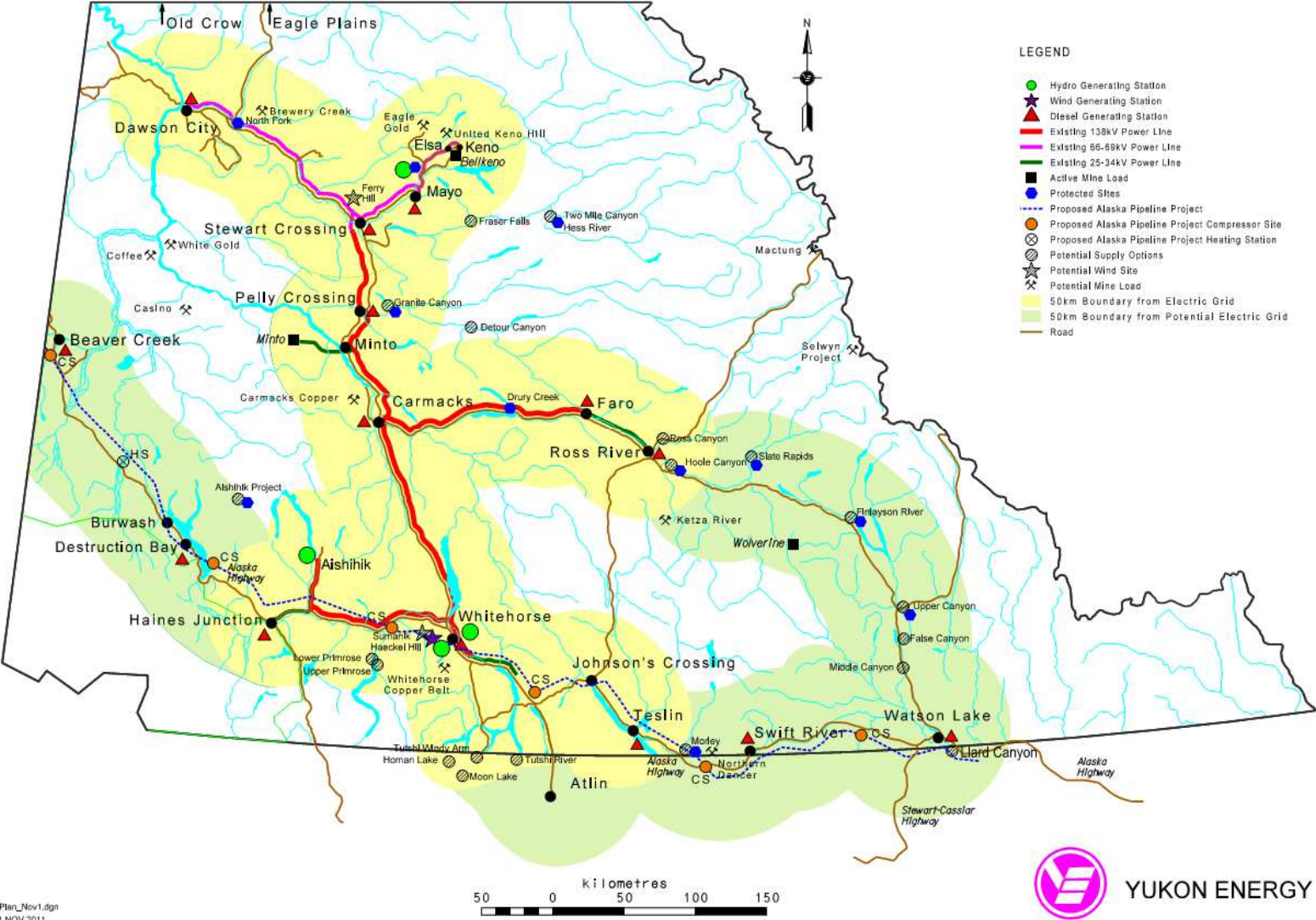
The current integrated Yukon grid reflects material Yukon Energy developments since the 2006 Resource Plan, including completion in 2011 of the Carmacks-Stewart Transmission Project to connect the Whitehorse-Aishihik-Faro (WAF) grid and the Mayo-Dawson (MD) grid, expansion of Mayo hydro capacity from 5 to 15 MW (Mayo B project), and the 7 MW enhancement of the Aishihik hydro facility. As a result of substantial federal and Yukon funding contributions, in 2012 these new grid power assets are already yielding ratepayer cost savings due to displacement of otherwise required costly diesel generation.

Grid capacity planning is required to not exceed a Loss of Load Expectation (LOLE) of 2 hours per year and, for non-industrial loads, to provide capacity adequate to accommodate loss of the system's largest generating or transmission-related generation resource (the "N-1" standard). Current capacity planning also provides for sufficient winter peak capacity reserve to accommodate loss of the Aishihik transmission line connection to Whitehorse.

Off-grid mine development has recently commenced at the Wolverine mine located south east of Ross River. The 2011 Resource Plan highlights many other potential off-grid mine developments over the next decade (locations for these projects are noted on Figure 2-1).

**Figure 2-1: Existing Yukon Power Infrastructure, Potential Supply Options, and Active & Potential Mine Loads**

LOCATION OF EXISTING POWER INFRASTRUCTURE AND POTENTIAL SUPPLY OPTIONS IN RELATION TO ACTIVE AND POTENTIAL MINE LOADS



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Figure 2-2 reviews historical power generation (1995-2010) by source for the WAF and MD grids. The following load changes are highlighted over this period:

- WAF – Faro mine closure in 1998 (82-100 GW.h/yr diesel immediately before shut down; no material diesel needed after shut down, except for low water year of 1999).
- WAF – Load growth since 1998 to the point that diesel generation starting to be needed again (impacts of non-industrial load growth plus recent Minto mine connection).
- Mayo Dawson – Grid expansion (15 GW.h/yr diesel reduction) – now connected to WAF.

**Figure 2-2: Yukon Grid Generation – 1995-2010 (GW.h/year)**

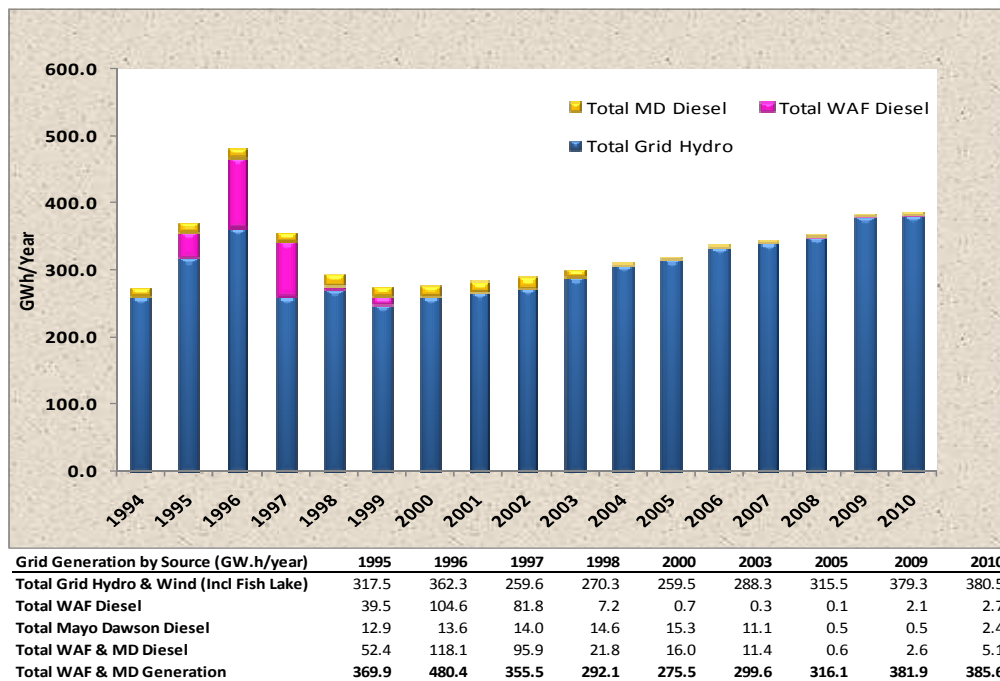
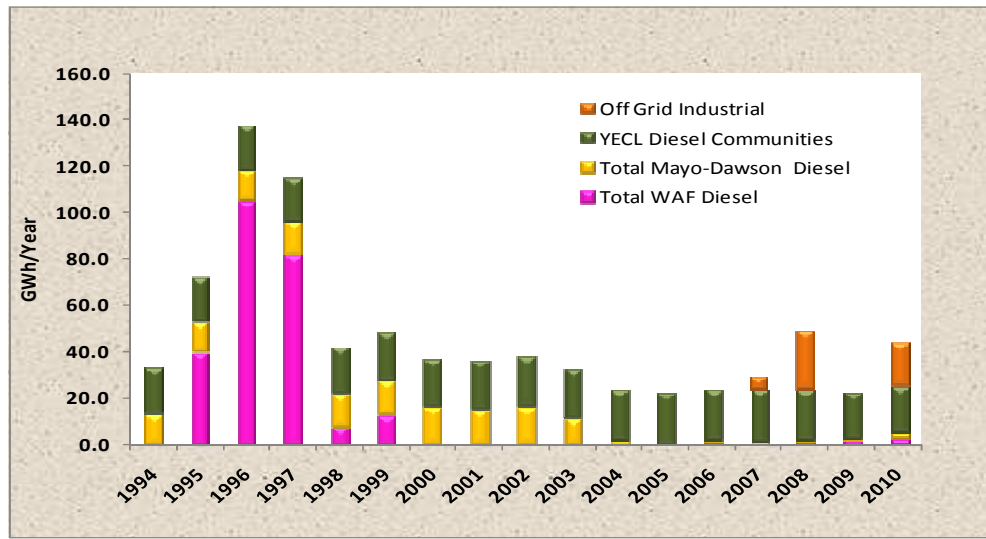


Figure 2-3 reviews historical (1995-2010) annual diesel generation and GHG emissions for the grid and off-grid loads. The following load changes are highlighted over this period:

- After closure of the Faro mine in 1998, off-grid communities accounted for almost all of the Yukon diesel generation.
- Off-grid Diesel Communities – YECL communities today at about 20 GW.h/yr (approximately 70.5% in Watson Lake).
- Off-grid Industrial – No off-grid mine loads until Wolverine in 2010 (19 GW.h that year).

Figure 2-3: Yukon Grid & Off-Grid Diesel Generation – 1995-2010 (GW.h/year)



| Diesel Generation (GW.h/year)        | 1995        | 1996         | 1997         | 1998        | 2000        | 2005        | 2008        | 2009        | 2010        |
|--------------------------------------|-------------|--------------|--------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Total WAF Diesel Generation          | 39.5        | 104.6        | 81.8         | 7.2         | 0.7         | 0.1         | 1.2         | 2.1         | 2.7         |
| Total MD Diesel Generation           | 12.9        | 13.6         | 14.0         | 14.6        | 15.3        | 0.5         | 0.4         | 0.5         | 2.4         |
| Off Grid YECL Diesel Communities     | 20.0        | 19.2         | 19.1         | 20.0        | 21.0        | 21.8        | 22.1        | 19.8        | 19.8        |
| Off-Grid Industrial                  | 0           | 0            | 0            | 0           | 0           | 0           | 25          | 0           | 19          |
| <b>Total Yukon Diesel Generation</b> | <b>72.4</b> | <b>137.4</b> | <b>114.9</b> | <b>41.8</b> | <b>37.0</b> | <b>22.4</b> | <b>48.7</b> | <b>22.4</b> | <b>43.9</b> |

\*OffGrid Industrial sales in 2007 and 2008 relate to estimates (not actuals) for Minto mine prior to interconnection with WAF grid.

| GHG Emissions (tonnes/year)             | 1995          | 1996          | 1997          | 1998          | 2000          | 2005          | 2008          | 2009          | 2010          |
|---|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| GHGs WAF                                | 27,668        | 73,189        | 57,283        | 5,039         | 510           | 80            | 850           | 1,495         | 1,882         |
| GHG's Mayo Dawson                       | 8,996         | 9,489         | 9,833         | 10,222        | 10,708        | 326           | 314           | 357           | 1,707         |
| GHG's Off Grid Communities & Industrial | 14,020        | 13,472        | 13,337        | 14,009        | 14,674        | 15,265        | 15,446        | 13,827        | 27,137        |
| <b>Total Yukon GHG's</b>                | <b>50,684</b> | <b>96,150</b> | <b>80,453</b> | <b>29,271</b> | <b>25,892</b> | <b>15,671</b> | <b>16,609</b> | <b>15,679</b> | <b>30,726</b> |

### **3.0 FUTURE YUKON POWER REQUIREMENTS – OVERVIEW**

Overall, forecast Yukon power requirements highlight the extent to which off-grid mine loads are expected to grow and dwarf grid loads within the next 5 to 10 years. To the extent this occurs, a fundamental shift will occur in Yukon power generation – affecting near-term opportunities for new fuel or other resource supply development options, ongoing Yukon GHG emissions, and potential options for future grid expansion concurrent with development of new longer-term legacy supply options in Yukon.

Figure 3-1 shows potential off-grid mine loads over a longer-term 40 year period (2011-2050) as projected in the 2011 Resource Plan. These off-grid mine loads are forecast to grow rapidly, surpassing grid loads as soon as the 2015-2020 time period, potentially exceeding 1,500 GW.h/year by 2020, and potentially continuing at over 1,300 GW.h/year for more than 20 years (beyond 2040) for new mines such as Casino, Selwyn and Northern Dancer. Off-grid projects are currently expected to rely upon diesel or LNG resource supply options for on-site power generation.

Figure 3-1 also shows over this same 40-year period (2011-2050) the existing Yukon grid system capability to supply potential grid loads as projected in the 2011 Resource Plan. Highlights from this figure include:

- Non-industrial grid load is projected in the 2011 Resource Plan to grow after 2010 at an annual rate of 2.26% based on recent trends<sup>3</sup>.
- Grid connected mine loads are assumed in the 2011 Resource Plan to include Minto and Alexco (which are currently connected to the grid) plus Whitehorse Copper Tailings (assumed to be connected in 2013), Victoria Gold (assumed in the 2011 planning to be connected in late 2013) and Carmacks Copper (assumed in the 2011 planning to be connected in late 2014)<sup>4</sup>.

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<sup>3</sup> The 2011 Resource Plan forecasts were prepared using 2010 actual results and do not reflect current YEC forecasts for 2012 and 2013 based on more recent information. Based on current forecasts through 2013 and 2.26% annual growth thereafter (and grid loss now assumed at 8.7%), grid non-industrial loads would be about 7.7 GW.h/yr higher in 2015 than projected in the earlier 2011 Resource Plan (with similar increases for subsequent years). See Appendix A to this Overview for current load forecasts.

<sup>4</sup> Changes in expected grid mine load forecasts since the 2011 Resource Plan forecasts were prepared include: Minto load growth occurring later in 2012; somewhat lower Alexco loads and higher Whitehorse Copper Tailings mine loads by 2014; delay in connection of Victoria Gold load until start of 2015 and expectation that this load will peak in summer and extend for a longer life than the seven years assumed earlier. No specific timing is currently forecast for Carmacks Copper mine connection to the grid, although the mine's developer (Copper North Mining Corp.) has recently announced (April 26, 2012) plans to submit a proposal to YESAB in Q3, 2012 based on design changes for the plans for development and closure of the project, and expects to submit plans for the Quartz Mining Licence amendment, revised Closure Plan, and a new Water Use Licence application immediately thereafter. Other potential future mine connections to the grid include Brewery Creek (potentially starting in 2013), Rau Gold and Ketz River.

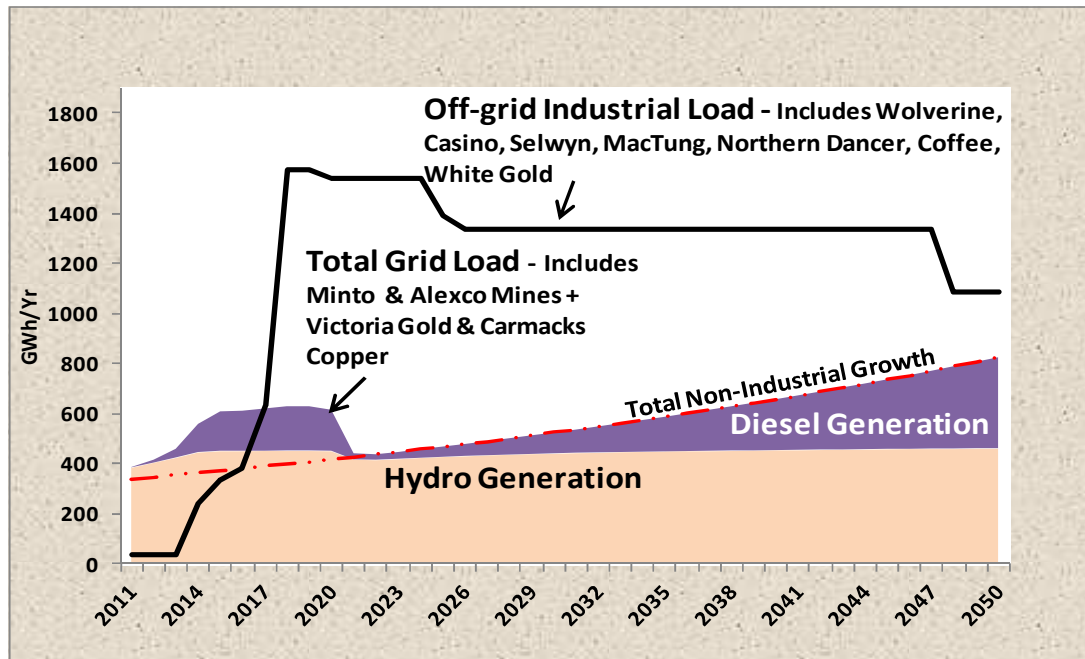
- Forecast grid diesel generation reflects the extent to which forecast grid loads exceed long-term average generation from existing and committed grid hydro and wind generation<sup>5</sup>.
  - Assuming no new resource supply developments, forecast grid diesel generation requirements exceed 150 GW.h/yr (2015-2020) with Victoria Gold and Carmacks Copper.
  - Grid mine loads are forecast in Figure 3-1 to stop by the early 2020s; thereafter, ongoing diesel growth reflects only non-industrial growth; in light of this impact, the 2011 Resource Plan tests the sensitivity of new resource options to different potential extensions of related grid diesel requirements to 2025 and 2030.

The 2011 Resource Plan forecasts as highlighted in Figure 3-1 were used in the initial 2011 analysis, as summarized in this Overview, to provide the initial assessment of overall options and priorities. However, expected grid mine loads continue to evolve. Mine and non-industrial grid load forecasts have been updated for the 2012/2013 Yukon Energy General Rate Application filed in April 2012 - and based on this information, updated near-term grid load forecasts have been prepared (see Appendix A to this Overview). These updates assist in ongoing near-term planning for specific new resource project options.

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<sup>5</sup> In these assessments, long-term average annual generation capability is assumed for existing hydro and wind resources (annual hydro generation capability is adjusted as required to reflect higher capability at higher annual grid load levels).

**Figure 3-1: Existing System Capability to Supply Potential Grid Load & Potential Off-Grid Mine Loads: 2011-2050<sup>6</sup> Excludes DSM/SSE - 2011 Resource Plan**



**\*Scenario B - Base Case Load Forecast with Victoria Gold, Carmacks Copper & WHCT**

|   | 2011*  | 2015    | 2020    | 2025    | 2030    | 2035    | 2040    | 2045    | 2050    |
|---|--------|---------|---------|---------|---------|---------|---------|---------|---------|
| <b>Grid Load/Hydro Supply Gap**</b><br>(Forecast Diesel Generation-GW.h/yr) | 2      | 158     | 163     | 40      | 83      | 138     | 204     | 278     | 364     |
| <b>Potential Off Grid Mines</b><br>(Forecast Diesel or LNG*** GW.h/yr)      | 37     | 332     | 1,538   | 1,390   | 1,338   | 1,338   | 1,338   | 1,338   | 1,088   |
| <b>Total Yukon Diesel or LNG Generation (GWh/yr)</b>                        | 39     | 490     | 1,701   | 1,430   | 1,421   | 1,476   | 1,541   | 1,616   | 1,451   |
| <b>Total Potential GHG's (tonnes)</b>                                       | 26,962 | 343,073 | 864,118 | 674,435 | 667,793 | 706,413 | 752,282 | 804,481 | 689,306 |

\* 2011 diesel generation is based on long term forecast (not actuals)

\*\* Assumes connection of Carmacks Copper and Victoria Gold to grid

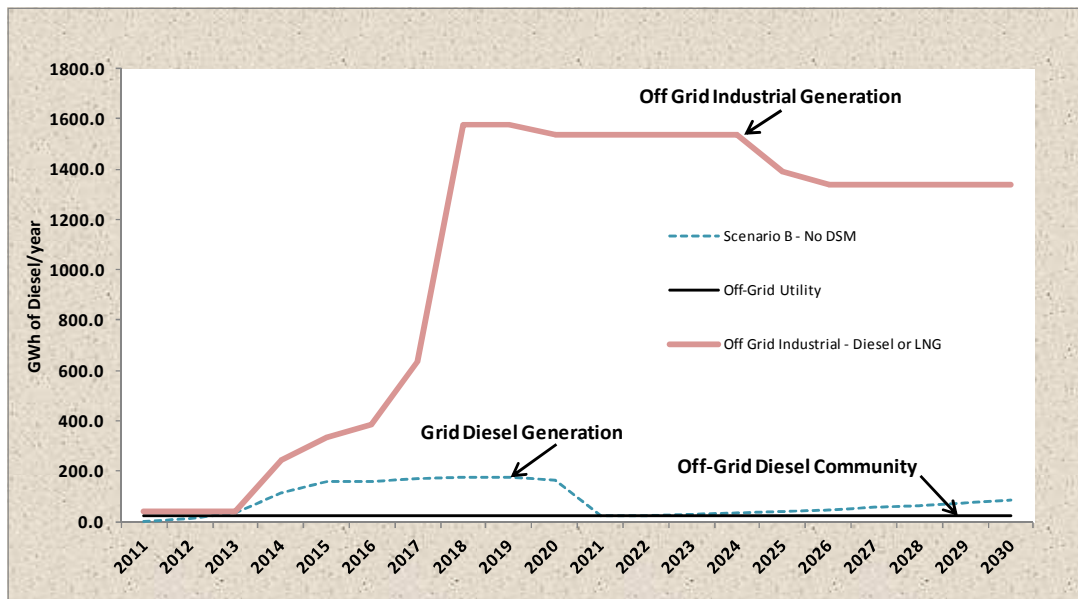
\*\*\*Assumes Casino develops using LNG with combined cycle power generation & other off grid mines develop using diesel

Figure 3-2 shows non-renewable generation during the 20-year planning period (2011-2030) for all grid and off-grid loads (forecast off-grid diesel community generation and potential off-grid mine diesel) with an accompanying table showing related GHG emissions. The figure and table further highlight the extent to which potential off-grid mine diesel or LNG generation could dwarf grid diesel generation by as soon as 2018-2019.

<sup>6</sup> Potential Alaska Highway Pipeline Project compressor station power loads not included in the above figure could potentially add 1,470 GW.h/year of additional equivalent energy requirements (six compressor stations). Forecasts prepared in 2011 noted that this could occur by approximately 2020/21 and be sustained over 25 years in the event that GHG emissions initiatives support electrification initiatives. Ongoing events in 2012 suggest that this project may be materially delayed.

As noted above, forecast grid diesel generation reflects the extent to which forecast grid loads exceed long-term average generation from existing and committed grid hydro and wind generation. Absent DSM/SSE and new mine loads connected to the grid after forecast mine loads end, Figure 3-2 indicates that on-grid diesel generation is forecast to grow from being minimal in 2011 to 40 GW.h by 2025, i.e., almost twice as large as the off-grid diesel community generation. Continuation of recent non-industrial grid load growth is forecast (without DSM/SSE) to result in 83 GW.h of grid diesel generation by 2030.

**Figure 3-2: Total Yukon Non-Renewable Generation (Grid & Off-Grid): 2011-2030  
 Excludes DSM/SSE - 2011 Resource Plan**



| <u>Diesel* Energy Requirement</u>                | <u>2011</u> | <u>2015</u> | <u>2020</u> | <u>2025</u> | <u>2030</u> |
|--|-------------|-------------|-------------|-------------|-------------|
| <b>Grid Diesel (YEC - Scenario B-no DSM/SSE)</b> |             |             |             |             |             |
| Diesel Generation (GW.h)                         | 1.5         | 158.1       | 163.3       | 40.3        | 82.8        |
| GHG Emissions (tonnes)                           | 1,062       | 110,673     | 114,304     | 28,220      | 57,979      |
| <b>Off Grid Diesel Communities (YECL)</b>        |             |             |             |             |             |
| Diesel Generation (GW.h)                         | 19.9        | 20.4        | 20.9        | 21.5        | 22.1        |
| GHG Emissions (tonnes)                           | 13,936      | 14,247      | 14,644      | 15,053      | 15,473      |
| <b>Potential Off Grid Mine Diesel* (GWh)</b>     |             |             |             |             |             |
| Diesel Generation (GW.h)                         | 37.0        | 332.0       | 1,537.8     | 1,389.8     | 1,337.8     |
| GHG Emissions (tonnes)                           | 25,900      | 232,400     | 749,814     | 646,214     | 609,814     |
| <b>Total Yukon</b>                               |             |             |             |             |             |
| Diesel Generation (GW.h)                         | 58.4        | 510.5       | 1,722.0     | 1,451.6     | 1,442.7     |
| GHG Emissions (tonnes)                           | 40,898      | 357,320     | 878,763     | 689,487     | 683,266     |
| * Includes LNG for Casino mine                   |             |             |             |             |             |

## **4.0 RANGE OF RESOURCE SUPPLY OPTIONS**

The 2011 Resource Plan identifies and assesses near-term (i.e., can be committed before 2015) as well as longer-term (i.e., can start construction before 2021) resource options in Yukon. Table 4-1 provides an overview of resource options considered at Yukon Energy's March 2011 Charrette.

- **Near-term options** are identified, i.e., potentially available to start construction before 2015. In addition to diesel and DSM/SSE, these include the following resource options:
  - Hydro enhancements – Limited potential added supply from Mayo Lake storage<sup>7</sup>, Marsh Lake storage, Aishihik licencing, Gladstone Diversion (cannot meet timing for short-term).
  - Thermal-Biomass – Wood biomass has potentially large supplies, relative to near-term needs (10 to 25 MW); municipal waste-to-energy (WTE) for up to 2.2 MW.
  - Thermal-LNG – Liquid natural gas (LNG) from BC gas source (potentially unlimited supply relative to Yukon needs over the planning period).
  - Wind – Ferry Hill or Mount Sumanik opportunities (up to 21 MW and about 56 GW.h/yr)
- **Longer-term options** are screened into the "hydro" greenfield site options potentially available to start construction by 2021 versus "other" options that require information, technology or other external action to be considered potentially available before 2021.
  - Longer-term hydro – Subject to adequate connected loads being committed and adequate ongoing resource planning being carried out prior to 2015, includes up to 70 GW.h/yr of small hydro (<10 MW) at 20-23 c/kW.h, over 2,070 GW.h/yr of medium hydro (11-60 MW) at less than 15 c/kW.h, and over 4,700 GW.h of large hydro (>60 MW) at less than 15 c/kW.h.
  - Other longer-term – Includes geothermal (needs exploration), nuclear (needs cost-effective proven technology, permitting experience), solar (needs cost-effective proven technology for Yukon market conditions), pipeline/natural gas (needs commitments by others re: Alaska Highway Pipeline [plans first gas by 2020, full gas by 2021], and/or potential Eagle Plain gas development), and grid connect to BC or Alaska (needs commitments by others).
- **Yukon Energy's resource planning principles** are also used to characterize at a high level each option as regards reliability, affordability, flexibility and environmental responsibility.

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<sup>7</sup> The 2011 Resource Plan assumes that Mayo Lake Storage (1 metre of added bottom storage) is approved prior to assessing new resource options. The earliest in service for this project is currently estimated to be after winter 2013/14.

**Table 4-1: Range of Resource Supply Options & Initial High Level Characterization**

|  |                                    | <b>RELIABILITY</b>  | <b>AFFORDABILITY</b>  | <b>FLEXIBILITY</b>   | <b>ENVIRONMENTAL RESPONSIBILITY</b>                      |
|--|------------------------------------|---|---|--|--|
|  |                                    | Reliable winter peak capacity, & reliable development (timing & cost)                       | c/kW.h (\$2010) if fully utilized                                   | Ratepayer cost risks re Mine Load Reductions   | Env. impact mitigation - reduction of GHG Emissions      |
| <b>NEAR-TERM</b><br>potentially available start to construction before end of 2014 (available no later than 2017)                    | DSM/SSE                            | MEDIUM - depends on uptake and type of DSM/SSE  | HIGH - <10 c/kW.h   | MEDIUM – reasonably flexible; curtailable as/when needed                                       | HIGH   |
|  | Diesel – existing default option   | HIGH - low cost peaking & reserve capacity on system; low regulatory risk                   | LOW- approx. 30 c/kW.h  | HIGH – low capital cost; save fuel & operating cost when load not there (summer/mine shutdown) | LOW- higher GHG & emissions than any other option        |
|  | Hydro Enhancements                 | MEDIUM – reliable winter energy but high regulatory risk                                    | HIGH <10 c/kW.h   | MEDIUM – reasonable flexible; - winter storage; long-term value                                | HIGH   |
|  | Thermal - Biomass (incl. waste)    | HIGH - baseload energy & capacity (no development planning to date)                         | MEDIUM - approx 15 c/kW.h; Scalability issues                       | LOW – not flexible – high capital cost; intended for yr-round energy supply                    | HIGH   |
|  | Thermal - Liquid Natural Gas (LNG) | HIGH - peaking & reserve capacity; low regulatory risk                                      | MEDIUM/HIGH – < 15 c/kW.h   | HIGH - low capital cost; save fuel & operating cost when load not there (summer/mine shutdown) | MEDIUM – 30% to 50% lower GHG emissions than diesel      |
|  | Wind                               | LOW – not add reliable peaking/ reserve capacity; not dispatchable; but low regulatory risk | MEDIUM – approx 15 c/kW.h; includes storage                         | LOW – not flexible – high capital cost & not dispatchable                                      | HIGH   |
| <b>LONG-TERM HYDRO</b> (greenfield) potentially available to start construction before 2021  | Small Hydro (< 10 MW)              | MEDIUM – reasonably reliable; medium regulatory risk  | LOW to MEDIUM(15 to > 20 c/kW.h)                                    | LOW – not flexible; high capital costs req’s sustained demand (30+ yrs)                        | MEDIUM- HIGH – minimal emissions; large footprint        |
|  | Medium Hydro (11 to 60 MW)         | MEDIUM – reasonably reliable; high regulatory risk  | LOW to MEDIUM (10 to 20 c/kW.h)                                     | LOW – not flexible; high capital costs req’s sustained demand (30+ yrs)                        | MEDIUM- HIGH – minimal emissions; large footprint        |
|  | Large Hydro (> 60 MW)              | MEDIUM – reasonably reliable; high regulatory risk  | HIGH – 5 to 11 c/kW.h   | LOW – not flexible; high capital costs req’s sustained demand (30+ yrs)                        | MEDIUM – HIGH – minimal emissions; large footprint       |
| <b>OTHER LONG-TERM</b> (require information, technology or other external action to be considered potentially available before 2021) | Geothermal (exploration)           | HIGH re: energy & capacity<br>LOW re: development risk as depends on successful exploration | HIGH - low cost to build and operate<br>LOW– high exploration costs | LOW – not flexible; high capital cost req’s sustained demand; Not dispatchable                 | HIGH – minimal emissions/ footprint                      |
|  | Nuclear                            | HIGH – baseload energy & capacity   | UNKNOWN   | LOW – capital intensive; req’s sustained demand;   | LOW-MEDIUM – low emissions; nuclear-specific env. issues |
|  | Solar                              | LOW - not dispatchable, dependant on sun availability                                       | LOW - high cost at this time 20 to 60 c/kW.h & req storage          | LOW - capital intensive; req’s sustained demand;   | HIGH   |
|  | Pipeline/ Nat gas                  | HIGH - provides peaking & reserve capacity; low reg. risk                                   | MEDIUM to HIGH (high cost to establish)                             | HIGH - low capital cost; save fuel & operating costs when no loads                             | MEDIUM - lower GHG emissions than diesel                 |
|  | Grid Connection (B.C. or Alaska)   | MEDIUM-HIGH   | LOW – high cost to provide  | LOW - capital intensive; may enhance greatly flexibility in Yukon                              | MEDIUM-HIGH – offers clean energy options                |

**Note:** "Affordability" in this table is assessed assuming adequate load to fully utilize the resource, e.g., greenfield large hydro lifecycle costs of 5 to 11 cents/kW.h assume full use of the resource throughout a 65 year life. In practice, project feasibility for each option depends on forecast lifecycle costs (LCOE) based on forecast utilization of the option over its life.

## **5.0 YUKON UTILITIES – DEFAULT DIESEL PORTFOLIO REQUIREMENTS**

The 2011 Resource Plan grid load forecasts indicate that the major near-term challenge is to reduce costs and GHG emissions by displacing diesel energy generation that would otherwise be required between 2014 and 2021. Higher costs for default diesel generated by Yukon Energy and Yukon Electrical will affect rates for utility customers throughout Yukon due to integrated and equalized rate setting directives to the Yukon Utilities Board.

Diesel is currently the “default” generation resource option in Yukon, i.e., diesel is the reliable, established and available supply option against which other new supply options must be assessed. The Default Diesel Portfolio option retains established diesel generation capacity on and off the grid (with unit replacements as required), and assumes new capacity is supplied only through new diesel units as required at relatively low capital costs. In effect, this option assumes that all forecast grid electrical energy and capacity requirements beyond those that can be supplied by currently existing or committed hydro and wind generation are reliably and flexibly met through diesel generation.

After an overview of overall default diesel portfolio costs and GHG emissions, Section 5 reviews load forecast scenarios for grid diesel generation requirements for energy and capacity. Key features of the Yukon grid default diesel use are then reviewed which drive flexibility requirements and ability to utilize new resources effectively, i.e., grid seasonality in diesel generation and annual variability in diesel generation due to annual changes in hydro generation. The sensitivity of grid diesel energy forecasts to a range of possible mine connection loads is outlined, and future off-grid diesel generation is also reviewed for utility communities and mines.

### **Default Diesel Portfolio Costs & GHG Emissions**

The concerns raised by the Default Diesel Portfolio option are high costs and high GHG emissions, each of which derive from the use of diesel fuel<sup>8</sup>.

Forecast grid generation accounts for a small portion of total GHG emissions forecast for the Yukon power generation sector<sup>9</sup>. This is the situation today (2011) and is forecast to remain the likely reality throughout the 20-year forecast period. Over the next several years prior to 2020, off-grid industrial load and related emissions are forecast to increase dramatically, effectively dwarfing on-grid load and GHG

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<sup>8</sup> Costs are also required to replace all existing diesel capacity (and to provide added capacity as needed) during the planning period. However, with regard to meeting these capacity planning requirements, diesel is a low cost option with minimal site-related environmental impact concerns.

<sup>9</sup> See Figure 3-2 shows total Yukon non-renewable generation (grid and off-grid) GHG emissions during the planning period under each grid load scenario without DSM/SSE; the figure includes off-grid utility communities and existing plus potential off-grid industrial (mines).

emissions. Addressing the GHG emission challenge related to off-grid loads also raises new power planning considerations well beyond those addressed in the 2006 Resource Plan. The potential near-term surge in off-grid mine development, however, also raises the opportunity to examine new renewable resource development options for commitment prior to 2021 to expand the grid and help to supply power requirements for major new industrial developments.

### **Grid Diesel Requirements Load Scenarios with and without DSM/SSE - Energy**

Each grid load scenario provides projections with no DSM/SSE and also with DSM/SSE that is assumed to secure a 67% reduction in annual non-industrial grid load growth each year starting in 2013<sup>10</sup>.

Forecast utility grid (integrated WAF and MD grids) diesel energy generation requirements for the 2011 Resource Plan (GW.h and incremental energy costs/year) are provided in Figure 5-1 for the following three grid scenarios focused on near-term (i.e., to 2015) mine load connection prospects<sup>11,12</sup>. Existing diesel capacity on the grid is more than adequate to supply forecast energy requirements under each of these near-term load scenarios.

- **Base Case** – Includes non-industrial loads growing at recent rates (2.26%/year) and current connected mines (Minto and Alexco – forecasts assume these mines remain on the grid until around 2020).
- **Scenario A** – Adds Victoria Gold mine to the grid Base Case in late 2013 (based on then available information, forecast assumes on grid for about 7 years, i.e. until end of 2020).
- **Scenario B** – Adds the potential Carmacks Copper mine and Whitehorse Copper Tailings mine to the grid Scenario A (based on then available information, forecasts assume on grid until 2021).

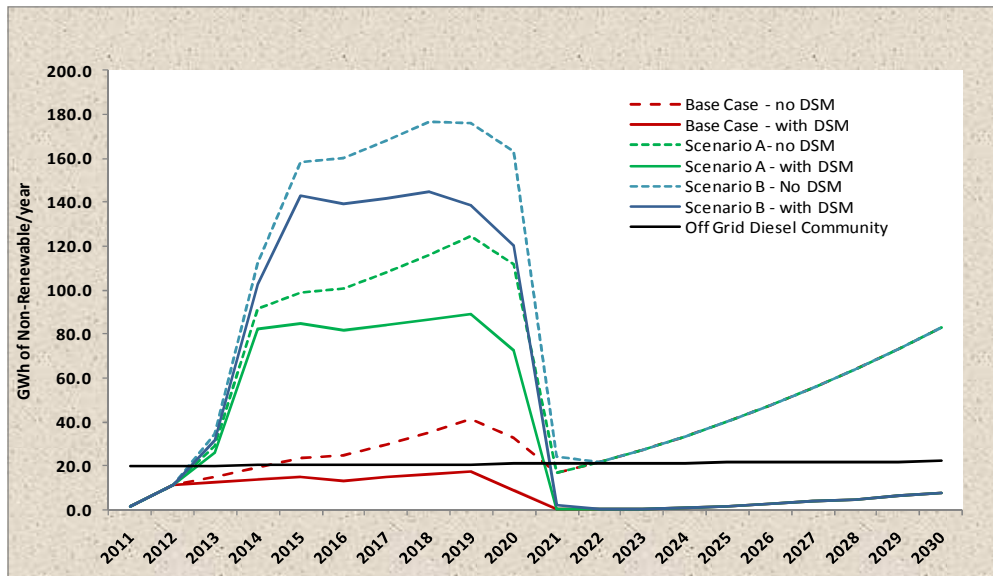
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<sup>10</sup> This range of potential diesel generation requirements is used to test the sensitivity of new supply options to potential DSM/SSE program impacts (DSM/SSE costs and programs are being addressed later in 2012 after completion of current studies and program development). DSM is also being addressed with industrial customers and is anticipated to provide some load reductions beyond those shown (potentially in the order of 10% of grid mine loads). Pending completion of current DSM/SSE studies, the 2011 Resource Plan assumes that DSM/SSE programs incur an average annual cost equal to 7.5c/kW.h (2010\$) of assumed energy load reduction.

<sup>11</sup> Figure 5-1 also shows forecast off-grid utility diesel generation requirements. Forecast diesel generation fuel and O&M costs reflect approved 2009 incremental diesel generation costs by rate zone escalated at inflation (2% per year) after 2010. Incremental grid diesel generation costs for fuel and O&M (2010\$) are assumed at 28c/kW.h (escalated at general inflation assumed at 2%/year), reflecting YEC's approved 2009 GRA fuel prices (e.g., 96 cents per litre at Whitehorse) and a 50/50 average of estimated costs for existing and new units (range of unit efficiencies and O&M cost). Diesel fuel prices in 2011 were generally higher than the approved 2009 fuel prices; however, based on October 2011 NYMEX futures, future diesel prices would be slightly lower than assumed in the Resource Plan (NYMEX futures based prices about 3% lower in 2012, 5% lower by 2015 and 6% lower by 2018).

<sup>12</sup> All loads (including mine loads) as forecast in 2011 based on then available information. Changes since the 2011 Resource Plan was prepared include: Minto load growth occurring later in 2012; somewhat lower Alexco loads and higher Whitehorse Copper Tailings mine loads by 2014; delay in connection of Victoria Gold load until start of 2015 and expectation that this load will peak in summer and extend for a longer life than the seven years assumed earlier. See Appendix A to this Overview for updates.

**Figure 5-1: Diesel Energy Requirements (Grid & Off-Grid Utility)  
Resource Plan Scenarios 2011 Resource Plan<sup>1</sup>**



| <b>Diesel Energy Requirement</b>       | <b>2011</b> | <b>2015</b> | <b>2020</b> | <b>2025</b> | <b>2030</b> |
|--|-------------|-------------|-------------|-------------|-------------|
| <b>Base Case (GWh)</b>                 |             |             |             |             |             |
| with DSM/SSE                           | 1.5         | 15.2        | 8.7         | 1.8         | 7.5         |
| without DSM/SSE                        | 1.5         | 23.7        | 32.5        | 40.3        | 82.8        |
| <b>Scenario A (GWh)</b>                |             |             |             |             |             |
| with DSM/SSE                           | 1.5         | 84.9        | 72.5        | 1.8         | 7.5         |
| without DSM/SSE                        | 1.5         | 98.9        | 112.0       | 40.3        | 82.8        |
| <b>Scenario B (GWh)</b>                |             |             |             |             |             |
| with DSM/SSE                           | 1.5         | 142.9       | 120.6       | 1.8         | 7.5         |
| without DSM/SSE                        | 1.5         | 158.1       | 163.3       | 40.3        | 82.8        |
| <b>Off Grid Diesel Community (GWh)</b> | 19.9        | 20.4        | 20.9        | 21.5        | 22.1        |

| <b>Diesel Energy Cost (Fuel &amp; O&amp;M)</b> | <b>2011</b> | <b>2015</b> | <b>2020</b> | <b>2025</b> | <b>2030</b> |
|--|-------------|-------------|-------------|-------------|-------------|
| <b>Base Case (\$ millions)</b>                 |             |             |             |             |             |
| with DSM/SSE                                   | 0.4         | 4.7         | 3.0         | 0.7         | 3.1         |
| without DSM/SSE                                | 0.4         | 7.3         | 11.1        | 15.2        | 34.5        |
| <b>Scenario A (\$ millions)</b>                |             |             |             |             |             |
| with DSM/SSE                                   | 0.4         | 26.3        | 24.8        | 0.7         | 3.1         |
| without DSM/SSE                                | 0.4         | 30.6        | 38.3        | 15.2        | 34.5        |
| <b>Scenario B (\$ millions)</b>                |             |             |             |             |             |
| with DSM/SSE                                   | 0.4         | 44.2        | 41.2        | 0.7         | 3.1         |
| without DSM/SSE                                | 0.4         | 48.9        | 55.8        | 15.2        | 34.5        |
| <b>Off Grid Community (\$ millions)</b>        | 5.9         | 6.6         | 7.5         | 8.6         | 9.9         |

<sup>1</sup> See Appendix A to this Overview for current updated diesel energy and other forecasts prepared since the 2011 Resource Plan.

Under each of the above grid scenarios, a robust and successful DSM/SSE program would see minimal diesel generation (and consequently minimal diesel cost impacts and diesel displacement opportunities) after shut down of connected mine loads (i.e., with assumed DSM/SSE and Scenario A or B assumed mine closures after 2020, there is less than 10 GW.h of required diesel generation annually over the period from 2021 to 2030). In contrast, no DSM/SSE program (or unsuccessful DSM/SSE programming over the period) would see much greater rate impacts and diesel displacement opportunities after 2020 (i.e., between 22 GW.h to 83 GW.h per year (2022-2030) under all “no DSM/SSE” scenarios that assume closure of connected mines after 2020-2021).

### **Grid Season Generation – Impacts on Diesel Generation**

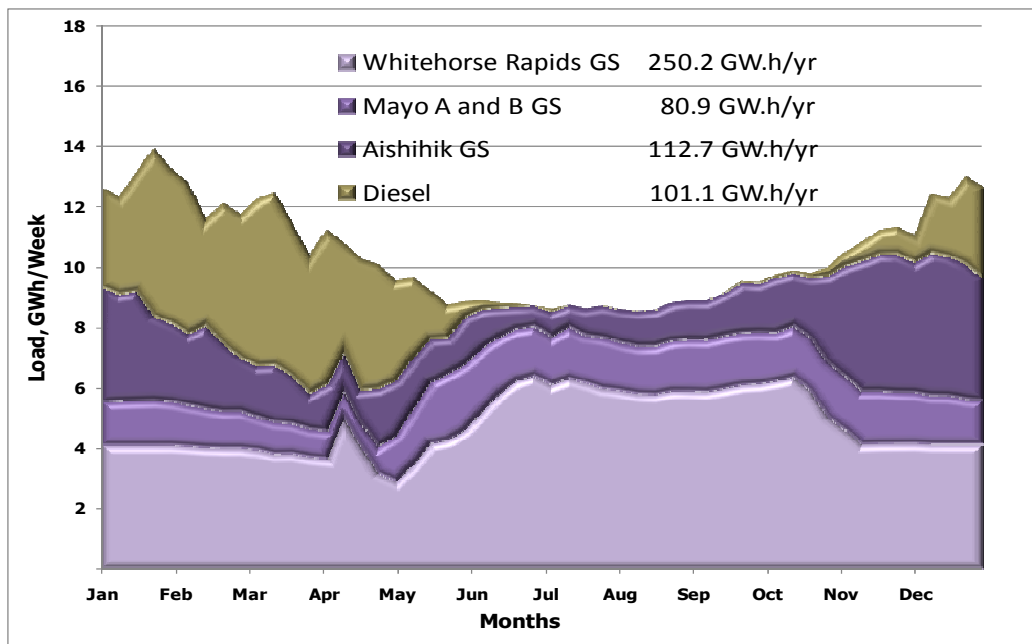
Diesel generation on the Yukon grid occurs in winter. As reviewed in Figure 5-2, with Scenario A 2015-2016 load and no DSM/SSE, 69% of annual near-term diesel generation forecast under average water conditions occurs in four winter months (December to March), and only 2% occurs in the five summer/fall months (June to October). Concentration of forecast diesel generation outside the summer/fall remains a key feature of the Yukon grid under a wide range of load and water conditions.

This concentration of grid diesel generation outside the summer/fall months reflects two factors: seasonal variation in grid loads (which are higher in winter than in summer) and seasonal variation in grid hydro generation for existing and committed facilities (hydro generation typically is higher in summer and fall as compared to winter/spring months). The seasonal concentration of grid diesel generation also reflects a key feature of Default Diesel, i.e., its flexibility to be utilized only when needed, reflecting both the technology (i.e., portable/storable fuel that is readily available) and its relatively low capital cost.

In contrast, Figure 5-3 shows seasonal generation at the Scenario A 2015-2016 load with a new 21 MW of wind generation providing 56 GW.h/year with year-round operation (reflects maximum near-term potential wind development at Ferry Hill). In an average water year, 88% of this new wind is used to displace diesel generation (this result is sensitive to assumed grid load and scale of wind generation):

- 49 GW.h of diesel displaced (70% directly displaced in winter, 30% through use of incremental stored hydro due to impact of wind’s summer generation);
- 52 GW.h of diesel energy generation requirements remain on the grid under the assumed load and scale of wind capacity; and
- Unlike diesel, the 21 MW of new wind generation is dependent at all times on wind availability and therefore does not contribute to grid reliable capacity requirements (i.e., diesel or other new reliable capacity is needed to address diesel unit retirements plus added capacity requirements from growth).

**Figure 5-2: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) at Scenario A 2015-16 Load without DSM/SSE  
Grid Load Net of Fish Lake and Wind**

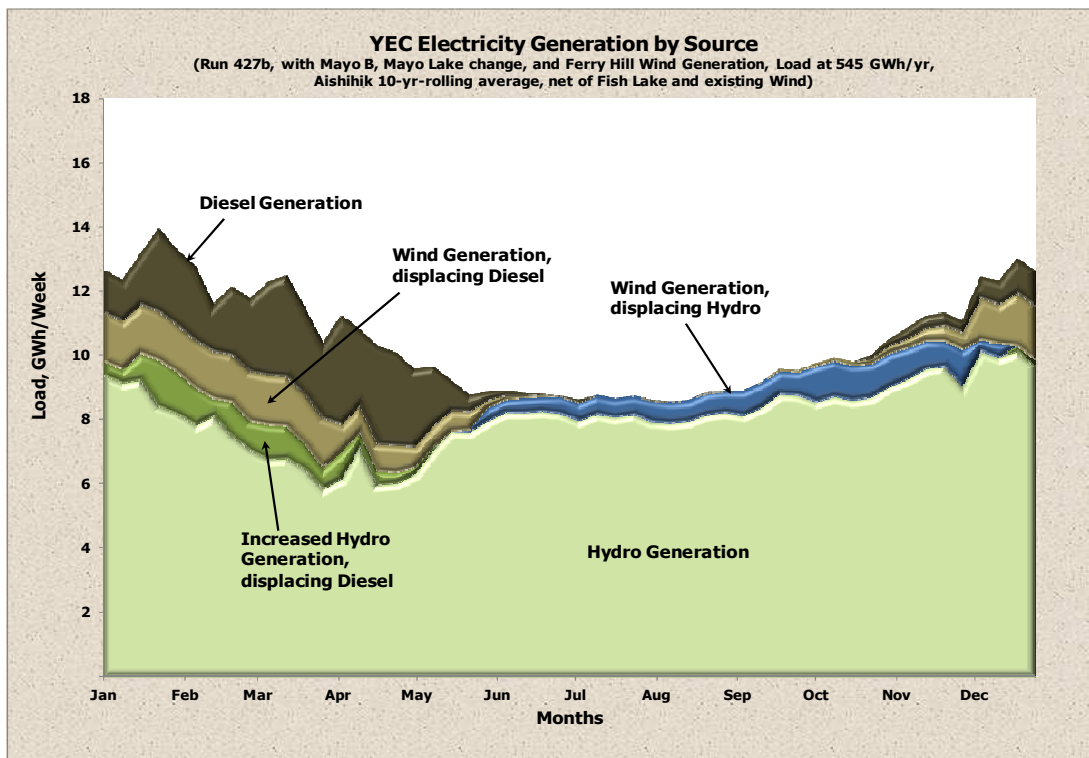


| GW.h                     | Jan-Mar  | April     | May       | June-Oct  | Nov       | Dec       | Annual |
|--------------------------|----------|-----------|-----------|-----------|-----------|-----------|--------|
|                          | Wks 1-13 | Wks 14-17 | Wks 18-22 | Wks 23-44 | Wks 45-48 | Wks 49-52 |        |
| <b>Diesel Generation</b> | 59.9     | 17.2      | 9.1       | 1.9       | 3.2       | 9.8       | 101.1  |
|                          | 59%      | 17%       | 9%        | 2%        | 3%        | 10%       | 100%   |
| <b>Hydro Generation</b>  | 100.5    | 25.3      | 37.1      | 199.0     | 41.3      | 40.6      | 443.9  |
|                          | 23%      | 6%        | 8%        | 45%       | 9%        | 9%        | 100%   |
| <b>Total Generation</b>  | 160.4    | 42.5      | 46.2      | 201.0     | 44.5      | 50.4      | 545.0  |
|                          | 29%      | 8%        | 8%        | 37%       | 8%        | 9%        | 100%   |

**Notes:** Weekly grid generation by source in Figure 5-2 from January to December is based on long-term average water flows and the Scenario A grid 2015-2016 load without DSM/SSE (assumes yet-to-be approved Mayo Lake project with amended licence for one metre of enhanced bottom storage):

- Seasonal loads (peak in winter and are lowest in summer).
- Current hydro generation supply (tends to peak in summer/fall, constrained in winter/spring).
- Diesel energy generation for average year is concentrated in winter months (60% in four months of December to March), and only 2% in five summer/fall months (June to October).
- Diesel energy generation forecast for average year at 101 GW.h (reflects impact of potential load growth by 2015/16, i.e., much lower grid diesel generation today based on average year).
- Diesel provides critical reliable grid capacity requirements to meet peak winter loads and reserve when hydro capacity can be constrained on the current grid, e.g., reliable winter hydro capacity approximates 24 MW at Whitehorse (out of 40 MW installed) and 11 MW at Mayo (out of 15 MW installed).

**Figure 5-3: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) with 21 MW Wind Project Displacing Diesel and Displacing Hydro at Scenario A 2015-16 Load Without DSM/SSE**



| Grid Generation at 545 GW/h load* (GW. Project | Without Wind Project | With 21 MW Wind Project | Change | Breakdown of Wind Generation Impacts (GW.h/yr) |
|--|----------------------|-------------------------|--------|--|
| <b>Grid Load</b>                               | 545.0                | 545.0                   |        | <b>Directly Displacing Diesel</b> 34.6         |
| <b>Grid Generation</b>                         |                      |                         |        | <b>Directly Displacing Hydro</b>               |
| Hydro*   | 443.9                | 437.3                   | (6.6)  | <b>Stored Hydro Displacing Diesel</b> 14.6     |
| Diesel   | 101.1                | 51.9                    | (49.2) | <b>Spilled Hydro (not required)**</b> 6.6      |
| Wind*  | -                    | 55.8                    | 55.8   | <b>Total Wind Project Generation</b> 55.8      |
| <b>Total</b>                                   | 545.0                | 545.0                   |        |  |

\* Existing Wind and Fish Lake generation not included.

**Total Displaced Diesel = 34.6 + 14.6 = 49.2 GW.h**

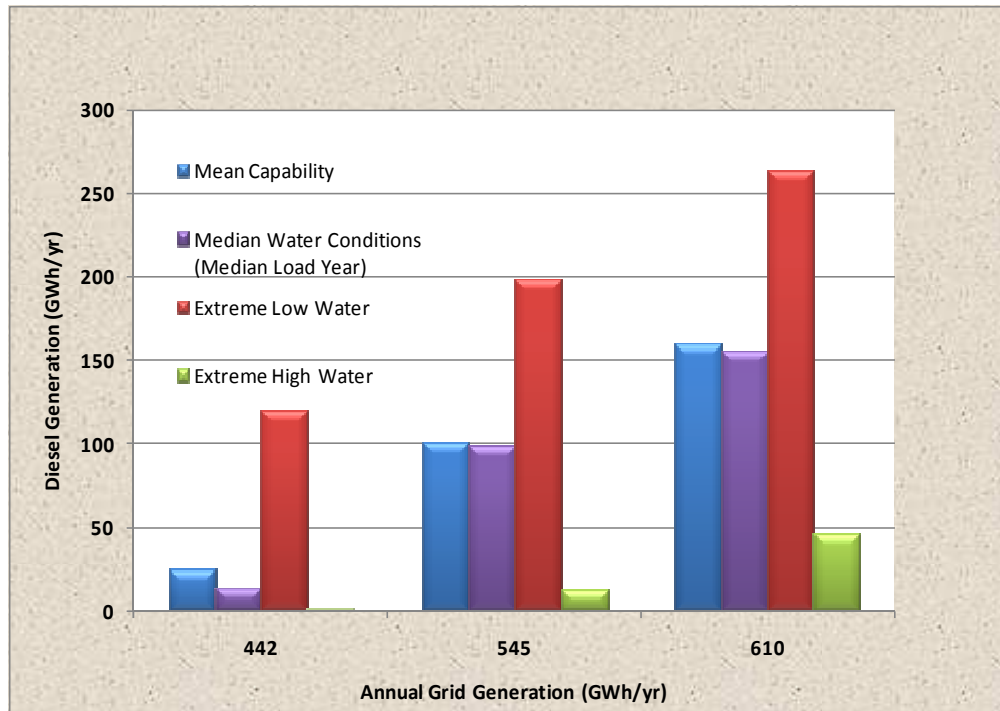
\*\*This figure provides an example that illustrates impacts this supply option would have on the existing generation system;

This does not suggest YEC would operate the system in a manner that results in hydro being displaced by other forms of more costly generation

### Annual Diesel Variability Due to Annual Hydro Generation Fluctuations

Figure 5-4 demonstrates the high variability that exists on the current Yukon grid regarding annual diesel generation requirements at any assumed grid load level. By way of example, at the Scenario A 2015-2016 load without DSM/SSE assumed in Figures 5-2 and 5-3, diesel generation can potentially range in any year from 13 to 199 GW.h/year, depending on water flow impacts on grid hydro generation.

**Figure 5-4: YEC Annual Grid Diesel Generation Variability at Different 2015-2016 Grid Loads (GW.h/yr)**



| Annual Diesel Generation (GW.h/yr)                | Annual Grid Load (GW.h/yr) |       |       |
|---|----------------------------|-------|-------|
|   | 442                        | 545   | 610   |
| <b>Mean Capability</b>                            | 24.6                       | 101.1 | 160.2 |
| <b>Median Water Conditions (Median Load Year)</b> | 13.6                       | 98.6  | 155.7 |
| <b>Extreme Low Water</b>                          | 119.7                      | 198.8 | 263.8 |
| <b>Extreme High Water</b>                         | 0.1                        | 13.0  | 46.2  |

**Notes:**

- The range of annual grid loads reflects approximate forecast 2015-16 loads ranging from Base Case (442 GW.h - no new mines) to Scenario A (545 GW.h – connect Victoria Gold) and Scenario B (610 GW.h – connect Victoria Gold, Carmacks Copper and Whitehorse Copper Tailings).
- An “extreme” or “median” year reflects one year out of 364 cases (28 water years and 13 load years). “Averaged load year” (which not shown above) is average annual value for a water year calculated over all 13 load years. For the 545 GW.h/year grid load, the extreme low water diesel generation for Averaged Water Year would require 166.7 GW.h/year diesel generation (reflects 1996 water year of record), and the extreme high water diesel generation for Averaged Water Year would require 34.1 GW.h/year diesel generation (reflects 1992 water year of record).

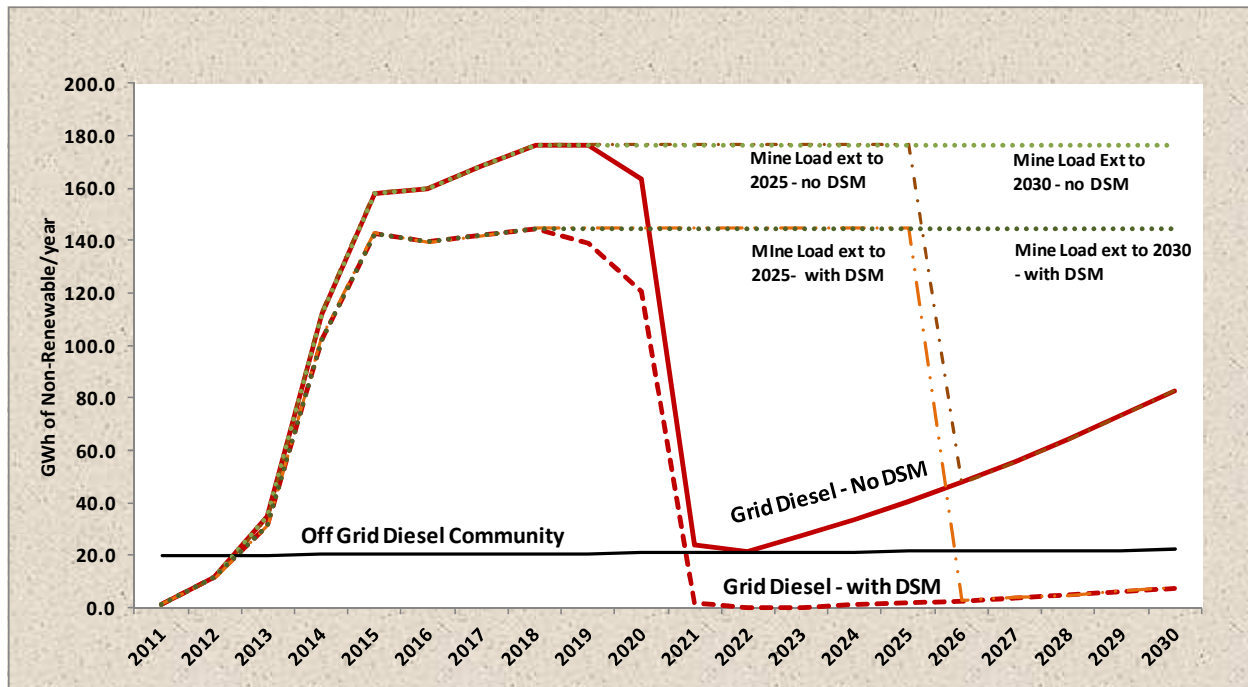
**Range of Possible Connected Mine Loads**

The 2011 Resource Plan recognizes that a wide range of possible variations in connected mine loads may occur over the 20-year planning period, including delays in connection of specific loads, extensions in the

life of any connected loads, earlier-than-expected mine shutdowns, new connections not currently forecast and expansions or contractions in connected loads.

- Beyond looking at a range of near-term mine connections (e.g., Base Case, Scenario A and Scenario B loads), resource option sensitivity for displacing grid diesel generation is also tested for different potential extensions of connected mine loads beyond the 2020 date after which the forecasts show shut down of connected mine loads (sensitivity is tested separately as shown in Figure 5-5 for extensions of related grid diesel requirements to 2025 and 2030).
- The potential for connection to the grid of material new off-grid mine loads (beyond those included in Scenario A and B) has been forecast to be very limited:
  - Off-grid industrial diesel or other fossil fuel power generation at the Wolverine mine (37 GW.h/year) already exceeds utility diesel generation (grid and off-grid). This load is over 270 km from the grid, and connection was never considered to be a practical option given this distance and an expected 10 year mine life.
  - There are currently only a limited number of potential new mine opportunities located within 50-100 km of the 69-138 kV grid (e.g., potentially Brewery Creek, Rau Gold, and Ketzka River); although none of these mine loads were included in the 2011 grid load forecasts, the developer of the Brewer Creek mine (Predator Mining Group Inc.) informed YEC that it would like to discuss connection to the grid potentially as soon as mid 2013 with a load of approximately 3.7 MW.
- Opportunities exist in the longer-term (i.e., commitments prior to 2021) to connect to the grid one or more of the major new off-grid mine loads that are driving potential off-grid diesel/LNG generation on a multi-decade basis as shown earlier in Figure 3-1. However, as noted, these mine loads are not being planned on the basis of any grid connection – and any potential grid connection in future will be contingent on new larger-scale renewable resources being developed that can supply a major share of the new off-grid power requirements on a timely and cost-effective basis. Looking at the largest of these potential off-grid mine loads (Casino), this opportunity translates into the challenge of developing new renewable resource options within the next decade that are less costly than the LNG (or natural gas fuelled generation if pipeline or Eagle Plain gas becomes available) that is currently planned to supply this load.

**Figure 5-5: Diesel Energy Requirements - Sensitivity Tests re: Mine Load Extensions**



**Forecast Grid Diesel Requirements - Capacity**

In addition to supplying energy requirements, diesel generating units are important for meeting grid capacity planning requirements, i.e., the required capacity to meet firm winter peak load requirements with adequate reserve. As reviewed in Table 5-1, over the 20-year planning period all of Yukon Energy’s existing diesel generation capacity (37 MW) is forecast to be replaced due to expected retirements. The following highlights are noted from Table 5-1:

- There are no forecast new grid capacity requirements in 2011 under any of the resource planning scenarios.
- By 2015, with DSM/SSE, there is no new grid capacity required under the Base Case scenario, and between 9.6 MW to 17.6 MW of new capacity required under Scenario A and Scenario B loads respectively (at a diesel capacity replacement cost of approximately \$15.7 million to \$28.7 million)<sup>13</sup>.
- By 2020, with DSM/SSE, 8.8 MW of new grid capacity is required under the Base Case scenario (at a diesel capacity replacement cost of \$15.8 million). New capacity required under Scenario A

<sup>13</sup> Cumulative diesel capacity spending to date after 2010 to meet capacity planning requirements (escalated dollars – assumed cost of \$1.5 million/MW [\$2010]).

and Scenario B loads is 17.9 MW and 25.9 MW respectively (at a diesel capacity replacement cost of \$30.6 million to meet Scenario A loads and \$43.6 million to meet Scenario B loads).

- By 2025, with DSM/SSE, under all scenarios 27.6 MW of new capacity is required at a diesel capacity replacement cost of between \$47.0 million and \$52.1 million.
- By 2030, with DSM/SSE, under all scenarios 37.1 MW of new capacity is required at a diesel capacity replacement cost of between \$67.0 million and \$72.1 million.

**Table 5-1: New Diesel Grid Capacity Requirements for Resource Plan Scenarios: 2011-30\***

|  | 2011 | 2015 | 2020 | 2025 | 2030  |
|--|------|------|------|------|-------|
| <b><u>New Diesel Capacity Requirement (MW)</u></b>               |      |      |      |      |       |
| <b>With DSM/SSE</b>  |      |      |      |      |       |
| N-1  | 0.0  | 0.0  | 8.8  | 27.6 | 37.1  |
| Base Case  | 0.0  | 0.0  | 8.8  | 27.6 | 37.1  |
| Scenario A   | 0.0  | 9.6  | 17.9 | 27.6 | 37.1  |
| Scenario B   | 0.0  | 17.6 | 25.9 | 27.6 | 37.1  |
| <b>Without DSM/SSE</b>   |      |      |      |      |       |
| N-1  | 0.0  | 2.8  | 18.0 | 43.5 | 60.4  |
| Base Case  | 0.0  | 2.8  | 18.0 | 43.5 | 60.4  |
| Scenario A   | 0.0  | 12.8 | 27.1 | 43.5 | 60.4  |
| Scenario B   | 0.0  | 20.8 | 35.1 | 43.5 | 60.4  |
| <b><u>Diesel Capacity Additions (\$Millions)<sup>1</sup></u></b> |      |      |      |      |       |
| <b>With DSM/SSE</b>  |      |      |      |      |       |
| Base Case  | 0.0  | 0.0  | 15.8 | 52.1 | 72.1  |
| Scenario A   | 0.0  | 15.7 | 30.6 | 50.0 | 70.0  |
| Scenario B   | 0.0  | 28.7 | 43.6 | 47.0 | 67.0  |
| <b>Without DSM/SSE</b>   |      |      |      |      |       |
| Base Case  | 0.0  | 4.7  | 31.7 | 81.0 | 116.9 |
| Scenario A   | 0.0  | 21.0 | 46.4 | 78.8 | 114.7 |
| Scenario B   | 0.0  | 34.0 | 59.4 | 76.3 | 112.2 |

1. Cumulative diesel capacity spending to date after 2010 to meet capacity planning requirements (escalated dollars - assumed cost of \$1.5 million/MW [\$2010]).

\*See Appendix A to this Overview for current updated diesel grid capacity requirement forecasts prepared since the 2011 Resource Plan.

Forecast timing for new diesel capacity will be affected by diesel unit retirements and new capacity requirements during the 2013-2020 period related to different load scenarios<sup>14</sup>. This 2011 Resource Plan analysis assumes that the 25 km line L172 between Takhini and Whitehorse is appropriately reinforced within the next few years so as to provide no line constraint, i.e., absent such reinforcement, additional capacity would be required in Whitehorse.

### **Off-Grid Utility Diesel Generation Requirements**

Off-grid utility community diesel energy power generation requirements are forecast to grow very slowly based on recent trends for the diesel rate zone communities served by Yukon Electrical (Watson Lake, three small diesel communities, and Old Crow). Off-grid utility community diesel generation exceeds grid diesel generation under the Base Case forecast with DSM/SSE. Off-grid utility community diesel capacity requirements are not addressed at this time.

### **Potential Off-Grid Mine Diesel Requirements**

Potential off-grid mine diesel/LNG energy generation forecasts indicate that unprecedented potential off-grid industrial power load growth before 2020 could easily dwarf current projected utility grid and off-grid diesel generation (see earlier Figure 3-1). Current forecasts indicate that industrial off-grid diesel and/or LNG power generation could potentially exceed 330 GWh/year by 2015 and 1,545 GW.h/year by 2020, and remain above 1,300 GW.h per year beyond the planning period (2030); by comparison, total grid load served by hydro, wind and diesel generation as projected in 2020 under Scenario B with no DSM/SSE is 614 GW.h/year, i.e., about 36% of the potential off-grid industrial generation by that date.

The larger potential off-grid longer-life mines which constitute most of the potential projected off-grid industrial load over the planning period (e.g., Casino, Selwyn, Mactung and Northern Dancer) are not currently considering connection to the Yukon grid in order to meet load requirements. The largest of these potential industrial loads (Casino project) is planning to use LNG at costs well below the cost of diesel, and Northern Dancer is also looking at the LNG option.

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<sup>14</sup> Forecast new default diesel capacity requirements by year on the grid for each load scenario reflect forecast peak loads under the grid load scenarios, forecast generation unit retirements, and Yukon Energy's grid capacity planning requirements to meet peak winter loads. During the 2015-2020 period connected mine loads as assumed in Scenarios A and B of the 2011 Resource Plan are expected to be sufficient potentially to affect capacity planning requirements (under updated assessments, this is assumed to occur under the Loss of Load Expectation [LOLE] planning requirements when industrial loads exceed 13 MW), while in other years the N-1 requirement (currently loss of the Whitehorse transmission connection to the Aishihik hydro plant) based on non-industrial loads is expected to determine new default diesel capacity requirements.

## **6.0 NEAR-TERM RESOURCE OPTIONS TO DEFAULT DIESEL**

Portfolio options examine the extent to which alternative resource combinations could effectively reduce grid diesel generation under different forecast load scenarios. Diesel generation is assumed to be retained in each portfolio to supply all generation requirements not supplied by other resources.

### **Near-Term Resource Options to Default Diesel**

Non-diesel resource options potentially available for in service by late 2014 that were selected for near-term portfolios include Marsh Lake Storage (6.4 GW.h/year potential), Wood Biomass Thermal (15 MW)<sup>15</sup>, Waste to Energy (WTE) Thermal (2.2 MW)<sup>16</sup>, Wind (21 MW)<sup>17</sup>, and Liquid Natural Gas (LNG)<sup>18</sup>. In contrast, Gladstone Diversion (36.6 GW.h/year potential) likely cannot be committed before 2016 at the earliest, but could potentially constitute a resource for in-service by late 2017.

Each of these near-term options were assessed in the 2011 Resource Plan based on then available information – recognizing that further feasibility work is required in each case to confirm costs and supply capabilities, and also to determine whether or not the option is feasible to be committed by the dates currently assumed.

- LNG and Wood biomass are options where sourcing fuel supply remained a significant issue at the time of the 2011 Resource Plan analysis, and it was recognized that further pre-feasibility analysis is required prior to relying on either of these options for near-term supply<sup>19</sup>. Ongoing work by YEC is focusing on confirming least-cost options whereby LNG supplies can be secured as required by late 2014<sup>20</sup>.
- Feasibility information for Marsh Lake Storage and Gladstone Diversion confirms the relatively low cost offered by each of these hydro enhancement options – however, each of these hydro

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<sup>15</sup> Resource Plan analysis determined that any larger scale Wood Biomass plant would be more costly under forecast grid loads (the plant scale exceeds forecast grid requirements for a thermal plant running throughout the year). In contrast, a 10 MW plant might merit review under lower Scenario A loads. Wood Biomass plants smaller than 10 MW (e.g., 3 MW) are being examined as possible pilot projects (see Section 8 of this Overview).

<sup>16</sup> The 2.2 MW scale was assessed to be an optimum scale based on projected available municipal solid waste (MSW) resource supplies and potential access to low cost wood biomass “waste” supplies to supplement MSW supplies.

<sup>17</sup> A smaller 10.5 MW option was examined, but was slightly less cost-effective at forecast loads than the 21 MW option (the latter option reflected estimated wind resource that could be developed at Ferry Hill).

<sup>18</sup> LNG capacity is adapted as required to the specific assumed load forecast (assumes BC based LNG supply not limited).

<sup>19</sup> It was assumed that LNG and wood biomass options could likely be committed before 2015 if selected for development, subject to sufficient studies and planning being carried out in a timely manner to resolve various feedstock supply issues. The 2011 Resource Plan (Section 6.1) reviewed recent studies that YEC has participated in with the developer of the Casino mine project to confirm the feasibility of near-term LNG supply chain options to Yukon from Kitimat or Fort Nelson, B.C.

<sup>20</sup> See YEC web site for: (a) January 2012 LNG Workshop background paper and presentations; (b) December 2011 Biomass background study and presentations.

projects is subject to material timing uncertainties related to regulatory and permitting processes, and further Yukon Energy planning work on Gladstone Diversion is also subject to securing local First Nation support for the project. Gladstone Diversion is examined as potentially being in-service by late 2017 (it is expected that this option cannot be committed before 2015 – the assessment examined the potential impact of securing this option by the end of 2017).

- Feasibility information is also available for Wind and WTE options – however, further feasibility work is required on each of these projects before commitments could be made to proceed with permitting activities<sup>21</sup>.

### **Energy and Capacity Supply Capabilities**

Overall, only a few of the available non-diesel resource options offer large scale energy generation supply potential relative to forecast Yukon diesel generation loads. Figure 6-1 highlights the gross energy supply capabilities of the near-term options relative to each of the forecast 2015-2019 grid diesel requirement load scenarios with and without DSM/SSE (the table below this figure reviews reliable capacity capabilities and capital costs for each resource supply option):

- **LNG** – LNG supply is the only option that can potentially displace all diesel energy loads as well as all new diesel capacity requirements at any near-term load.
- **15 MW Wood Biomass** – Gross energy capability of a 15 MW wood biomass option exceeds all but Scenario B diesel energy loads; however, after seasonal diesel requirements and annual hydro variability impacts are considered, this option's net energy displacement of diesel is much lower than the gross energy capability, e.g., assuming Scenario A with DSM/SSE, net energy diesel displacement approximates only 72 GW.h of the 119.6 GW.h annual gross energy. This option can displace only a portion of new diesel capacity requirements (at this scale of plant, the only identified potentially feasible locations are either in Whitehorse or in the Minto burn area).
- **Other Near-Term Options** – Gross energy capability of other near-term options only displace portions of Scenario A diesel requirements, and net energy capability to displace diesel is lower than gross capability, e.g., approximately 80% to 88% of WTE or Wind gross generation displaces diesel with Scenario A load; minimal contributions from Marsh Lake hydro and WTE; wind provides minimal capacity contribution.

In summary, LNG can provide flexible amounts of supply up to any load levels likely to be required and Wood Biomass can also provide relatively large amounts of annual generation (119.6 GW.h/year for a 15

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<sup>21</sup> See YEC web site for October 2011 Waste to Energy Workshop background study and presentations.

MW plant, of which 72 GW.h would displace diesel generation under Scenario A loads with DSM/SSE<sup>22</sup>. In contrast, maximum potential levels of annual generation are limited from Marsh Lake (6.4 GW.h/year), 2.2 MW WTE (17.1 GW.h/year), Gladstone Diversion (36.6 GW.h/year), and Wind (55.6 GW.h/year).

Ongoing studies are defining the economic potential for DSM and SSE as well as specific programs and costs. Pending completion of these studies, the 2011 Resource Plan assumes that a specific level of DSM/SSE will be implemented starting in 2013 for non-industrial grid loads<sup>23</sup> and tests the sensitivity of all non-diesel supply options to these potential DSM/SSE impacts. In summary, notwithstanding the materially higher diesel displacement opportunities and higher Default Diesel Portfolio costs with no DSM/SSE, comparative feasibility assessments of the different resource portfolio options under load scenarios with DSM/SSE were not generally changed by consideration of load scenarios with no DSM/SSE<sup>24</sup>. Accordingly, the following summary overview analysis of resource and portfolio options typically focuses solely on review of load scenarios with DSM/SSE.

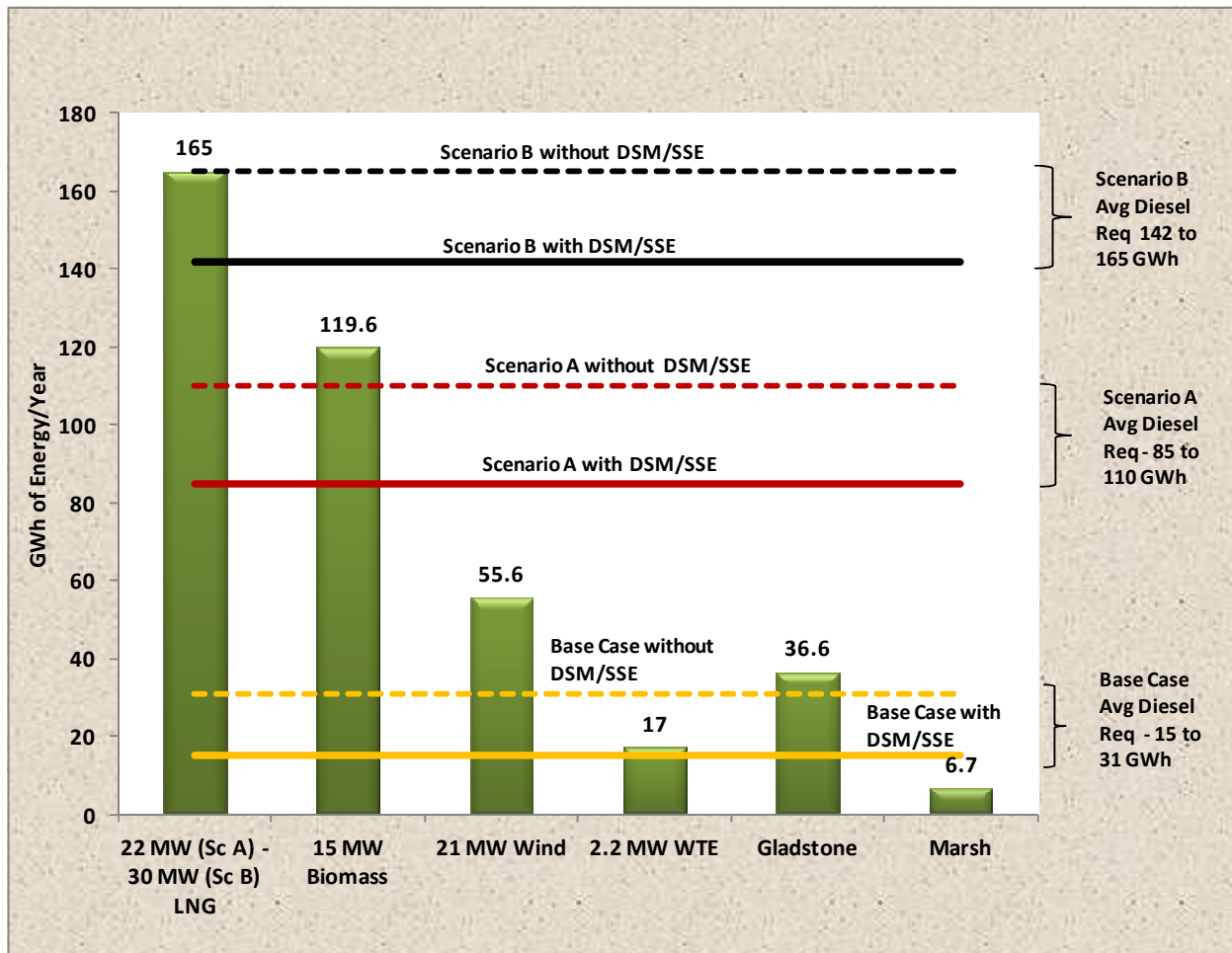
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<sup>22</sup> Studies suggest that a 25 MW plant scale located in Whitehorse might also be feasible, with annual generation approaching 200 GW.h/year; however, under Scenario A loads with DSM/SSE, less than 15% of the annual biomass energy over the project life would displace diesel generation (even during the 2015-19 period with mine loads connected, less than 100 GW.h/yr of the wood biomass generation would be used to displace diesel generation).

<sup>23</sup> Although the timing and level of future DSM/SSE remains uncertain, preliminary study results suggest that future DSM/SSE load reduction impacts over the period to 2030 may be within 50-75% of DSM/SSE assumed in the 2011 Resource Plan.

<sup>24</sup> Higher loads assuming no DSM/SSE tend to improve cost savings for all non-diesel portfolio options when compared with the Default Diesel Portfolio, and reduce somewhat the penalties faced by non-flexible options such as Wind when grid loads drop due to mine closures. Portfolios that include Gladstone Diversion tend in particular to show improved (lower) present value costs over the planning period with higher loads assuming no DSM/SSE. However, the overall cost ranking of LNG Transition Portfolio Options relative to Minimum GHG Portfolio Options or the Default Diesel Portfolio is not materially changed without DSM/SSE.

**Figure 6-1: Gross Energy Supply Capabilities by Near-Term Option (GW.h/yr During 2015-2019) – Compared to Diesel Requirements by Load Scenario with and without DSM/SSE (Net Energy Displacement of Diesel may be less than Gross Energy)**



**Notes:** Reliable Capacity capability (up to 37 MW new grid capacity needed by 2030 with Scenario A load with DSM/SSE):

- **Diesel, LNG** – Each can provide all of the firm capacity required (capital cost of \$1.5 million/MW assumed; for LNG cost of \$1.8 million/MW for combined cycle).
- **Wood Biomass** - Option assumes 15 MW of firm capacity (capital cost of \$5.7 million/MW).
- **Waste-to-Energy (WTE)** - 2.2 MW of firm capacity (capital cost of \$17.7 million/MW).
- **21 MW Wind** – Wind generation does not provide any reliable capacity; the option includes 5 MW of DRUPS (diesel rotary uninterruptible power) to enhance reliability, and this adds 5 MW to reliable capacity. Wind option capital cost of \$3.6 million/MW for 26 MW (wind & DRUPS).
- **Gladstone and Marsh** – Gladstone Diversion hydro adds minimal or no reliable capacity (due to Aishihik Transmission line vulnerability); Marsh Lake hydro storage adds about 1 MW reliable capacity. Overall capital costs are estimated at \$40 million for Gladstone and \$10.5 million for Marsh Lake storage. Earliest potential in-service for Gladstone is late 2017.

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**2015-2020 Average Annual Costs per kW.h**

New resource supply options display widely varying annual ratepayer cost impacts per kW.h during the 2015-2020 period with assumed connected mine loads (see Figure 6-2 for annual ratepayer costs per kW.h with Scenario A loads and DSM/SSE, assuming average annual hydro generation):

- **LNG and Hydro Enhancements (Marsh & Gladstone) are lowest cost** – LNG and hydro enhancements cost less than 20 c/kW.h each year relative to diesel fuel and O&M (new diesel units) at approximately 30 c/kW.h or higher (LNG fuel and O&M cost is lowest at 11 to 13 c/kW.h)<sup>25</sup>.
- **Wind and WTE slightly lower cost than Diesel** – Wind and WTE cost typically between 25 and 30 c/kW.h<sup>26</sup>; these capital intensive options are sensitive to load decline that is forecast starting in 2020 (lower loads result in higher average costs per kW.h).
- **Wood Biomass costs more than Diesel** – Wood biomass costs at or slightly below 35 c/kW.h until 2020, when costs rise above 35 c/kW.h<sup>27</sup>; this is a capital intensive option that is sensitive to load decline as forecast starting in 2020 (lower loads result in higher average costs per kW.h).

In summary, LNG is a flexible low capital cost option where unit fuel costs determine overall annual costs per kW.h. In contrast, higher capital costs per MW for other options result in costs per kW.h being sensitive to option scale and assumed grid loads.

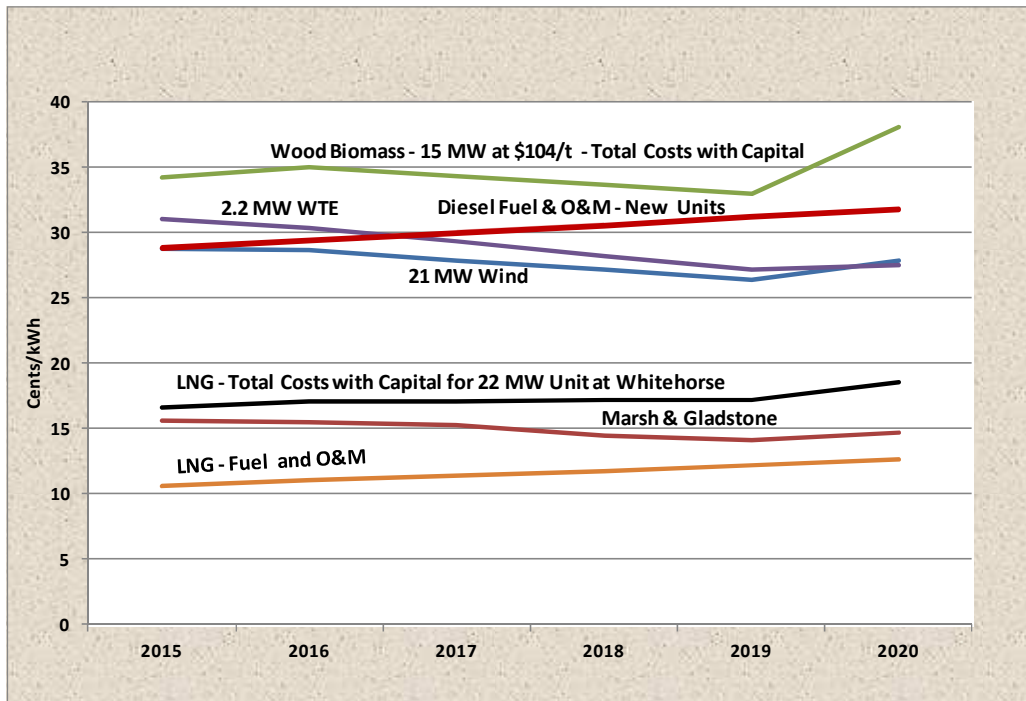
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<sup>25</sup> Forecasts assume diesel fuel and O&M cost escalation at 2% year (fuel price as approved by YUB in place in 2010). LNG costs assume 22 MW combined cycle generation units at Whitehorse (50% energy efficiency [6.562 Mcf/MW.h] and 44% average annual plant capacity factor) with LNG supplied by truck from Kitimat at cost of 2.7 cents per kW.h (2010\$) for all LNG supply costs other than LNG fuel; cost of LNG fuel at assumed natural gas price in BC plus \$3/MMBtu (2010\$) to reflect conversion costs and impact of export pricing; assumed BC gas price at \$5.5/MMBtu in 2015 (\$6.07/MMBtu after inflation), \$6.60/MMBtu in 2020 (\$8.05/MMBtu after inflation) and \$7.45/MMBtu in 2030 (\$11.07/MMBtu after inflation). Although combined cycle provides opportunity for waste heat sales in Whitehorse, no waste heat revenue offsets assumed with LNG option in this analysis.

<sup>26</sup> Assumes use 25,000 ODT/year of MSW plus 3,800 ODT/year wood biomass at Whitehorse WTE plant, with district heat net revenues, tipping fees and other revenues of \$3.3 million per year (2010\$). See Figure 6-3.

<sup>27</sup> Wood Biomass plant assumed to be located adjacent to grid in Minto burn area with wood biomass requirement of 0.7 ODT/MW.h at an average cost (2010\$) of \$104/per ODT. Assume 2%/year inflation of costs.

**Figure 6-2: Average Annual Costs per kW.h for Near-Term Resource Options – 2015-2020 (Scenario A Load with DSM/SSE – Cost Inflation at 2%/yr; higher for LNG)**



| Annual Cost (cents/kW.h)       | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|--------------------------------|------|------|------|------|------|------|
| Diesel Fuel & O&M - new units  | 29   | 29   | 30   | 31   | 31   | 32   |
| Wood biomass 15 MW at \$104/t  |      |      |      |      |      |      |
| Total Costs                    | 34   | 35   | 34   | 34   | 33   | 38   |
| Fuel + O&M                     | 19   | 20   | 20   | 20   | 20   | 24   |
| 21 MW Wind                     | 29   | 29   | 28   | 27   | 26   | 28   |
| 2.2 MW WTE                     | 31   | 30   | 29   | 28   | 27   | 28   |
| LNG - total costs with capital | 17   | 17   | 17   | 17   | 17   | 19   |
| LNG - fuel & O&M               | 11   | 11   | 11   | 12   | 12   | 13   |
| Marsh & Gladstone              | 16   | 15   | 15   | 14   | 14   | 15   |

**Note:** Assumes 2%/yr inflation for 2010\$ costs, except for LNG fuel cost which assumes specific real escalation of the 2010\$ natural gas price as well as overall inflation at 2%/yr (per footnote 24 at page 28). All costs assume average annual hydro generation each year during the period.

## **Lifecycle Costs per kW.h (LCOE)**

Resource options are more effective in displacing grid diesel generation to the extent that they can be focused in the priority diesel generation periods (winter/spring) and flexible to address relatively wide variability in annual hydro generation capability<sup>28</sup>.

Figure 6-3 provides, by option, forecast lifecycle costs of energy (LCOE) per kW.h (2010\$) of generation used to displace forecast diesel over the economic life of each option<sup>29</sup>. Separate LCOE forecasts for Scenario A load with DSM/SSE, for sensitivity tests for mine load diesel displacement extended to 2025 and 2030, and for full utilization of all generation to displace diesel are summarized below:

- **Forecast LCOE with no mine loads after 2021** – Only LNG and Marsh Lake & Gladstone have LCOE less than 30 c/kW.h (13.1 c/kW.h for Marsh/Gladstone and 18.4 c/kW.h for LNG); the highest LCOEs are Wind option (40 c/kW.h) and Wood Biomass (60.8 c/kW.h).
- **Forecast LCOEs decline as mine load diesel displacement is extended** – With mine loads extended to 2025, only LNG and Marsh Lake & Gladstone have LCOE less than 20 c/kW.h (10.1 c/kW.h for Marsh/Gladstone and 15.2 c/kW.h for LNG), and the highest LCOEs are Wind (26.5 c/kW.h) and Wood Biomass (37.1 c/kW.h) – with mine loads extended to 2030, further LCOE declines occur without changing the cost ranking of the options.
- **Full Utilization LCOE do not reflect forecast diesel displacement** – Forecast LCOEs with no mine loads after 2021 are much higher than Full Utilization LCOE which assume all generation can always be fully used to displace diesel, e.g., 53% higher for LNG (Forecast LCOE vs. Full Utilization LCOE), 111% higher for Marsh/Gladstone, 133% higher for WTE, 176% higher for Wind and 285% higher for 15 MW Wood Biomass.

Figure 6-4 demonstrates how Full Utilization generation varies from Forecast net diesel displaced with Scenario A loads for a Wind option over a 25 year economic life (highlights the impact of mine shutdown when the resource has no flexibility to limit its ongoing generation or costs).

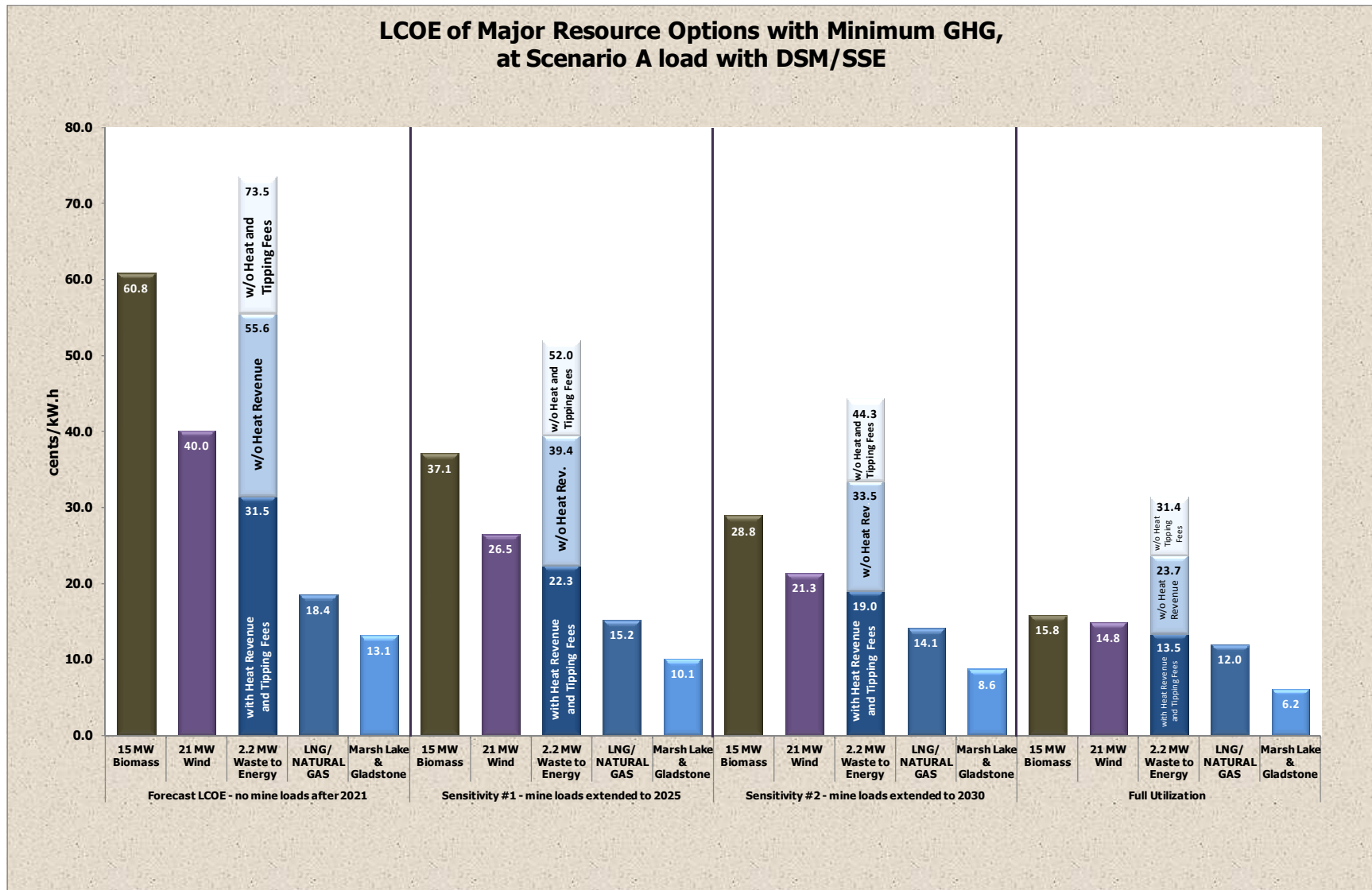
In summary, LNG and Hydro Enhancements (Marsh Lake & Gladstone Diversion) have the lowest LCOE, and Wood Biomass has the highest LCOE, under all Scenario A cases examined in Figure 6-3.

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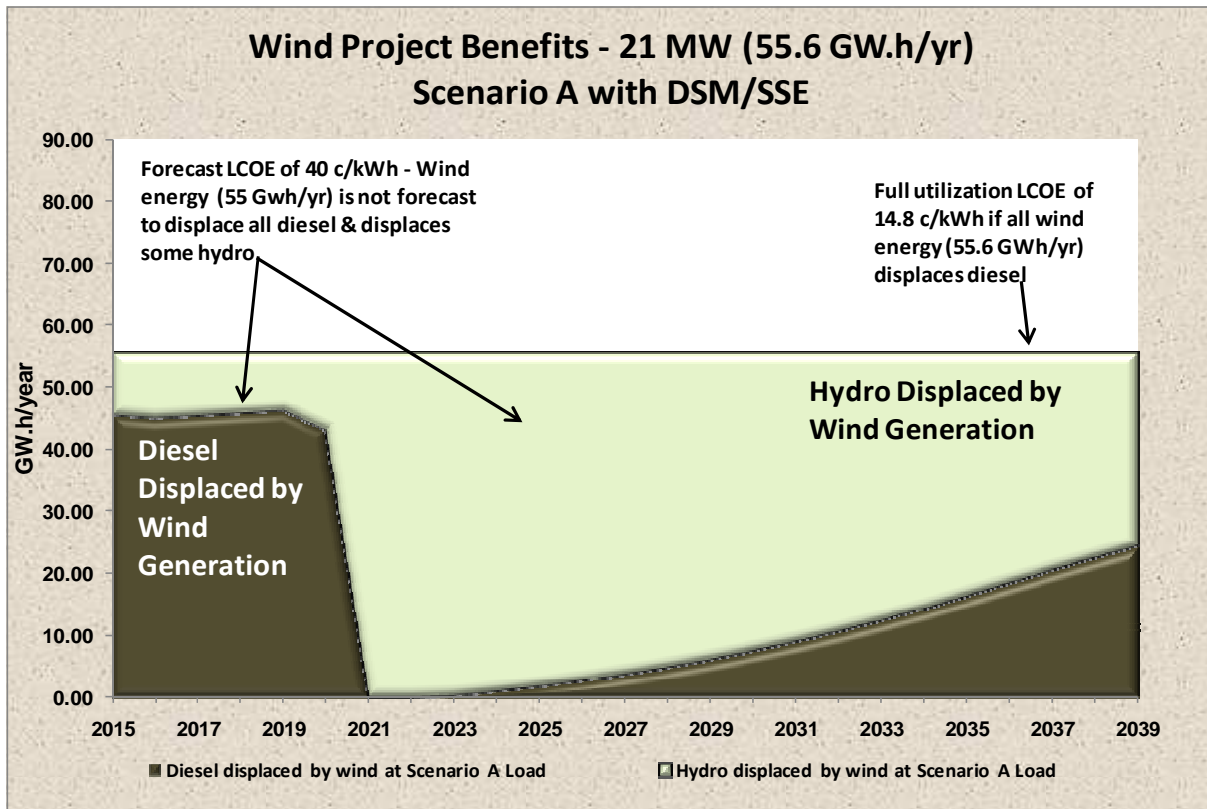
<sup>28</sup> This reality reflects the lack of grid connection in Yukon to external markets - and the resulting need to ensure where feasible that local generation matches the local grid load requirements (as surplus generation cannot otherwise be usefully used or sold). See Section 5 regarding grid hydro seasonal load and supply characteristics, as well as annual hydro supply variability. In the end, resource options for the grid in Yukon are valued based on ability to displace diesel generation, i.e., generation that is surplus to diesel displacement needs has little if any value to ratepayers.

<sup>29</sup> LCOE and present value cost assume discount rate of 6.56%/year for new generation assets based on YEC's 2009 GRA approved return on equity and cost of new long-term debt. Assumed project life varies by resource option, e.g., 20-years for LNG, 25 years for WTE and Wood Biomass and Wind, 65 years for Hydro enhancements.

Figure 6-3: Forecast Lifecycle Cost of Energy (LCOE - 2010\$) by Near-Term Option - Scenario A Load with DSM/SSE



**Figure 6-4: Wind Project: Displacing Diesel and Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021)**



**Near-Term Portfolio Options to Default Diesel**

Alternative portfolios including each of the above near-term resource options have been reviewed considering grid economic impacts, Yukon greenhouse gas emissions impacts and long-term development considerations. Near-term cost and rate impacts vary significantly depending in large part on the capital intensive nature of each resource option and its flexibility relative to major forecast load reductions after 2020 under all resource plan forecast scenarios.

Table 6-1 provides an overview of different resource portfolio near-term options identified in the 2011 Resource Plan (Scenario A grid loads with DSM/SSE are assumed for this table)<sup>30</sup>.

<sup>30</sup> The same Resource Portfolio Options apply for Scenario B loads with DSM/SSE, and for Scenario A or B loads with no DSM/SSE, subject to the LNG plant being 30 MW capacity rather than 22 MW capacity. Base Case Portfolio Options are more limited due to smaller scale of the diesel displacement loads, e.g., with DSM/SSE the options are Marsh Lake Storage & 2.2 MW WTE for Minimum GHG Portfolio, and LNG 4 MW or Marsh Lake Storage & LNG 4 MW for LNG Transition Portfolio [if no DSM/SSE, LNG plant scale increased to 8 MW]; for Base Case loads, LNG options assume simple cycle power plant (40% energy efficiency) and reliance on LNG availability in Yukon to supply off-grid mine loads.

In addition to the Default Diesel Portfolio, the following Portfolio Options are identified (resource options assumed to be in operation by start of 2015, except for Gladstone Diversion [assumed in operation by start of 2018]):

1. Minimum GHG Portfolio Options:

- a. Marsh Lake Storage & 15 MW Wood Biomass (89-92% reduction of grid diesel GHG for 2015-2019 period)<sup>31</sup>.
- b. Marsh Lake Storage, Gladstone Diversion & 21 MW Wind (60-61% reduction of grid diesel GHG for 2015-17 period and 84-85% for 2018-19 period [after Gladstone]).
- c. Marsh Lake Storage, 21 MW Wind & 2.2 MW Waste-to-Energy (WTE) (70-74% reduction of grid diesel GHG for 2015-2019 period).

2. LNG Transition Portfolio Options:

- a. Marsh Lake Storage & LNG (22 MW) (52% reduction of grid diesel GHG for 2015-2019 period).
- b. LNG (22 MW) (48% reduction of grid diesel GHG for 2015-2019 period).

Table 6-1 compares the present value (PV) incremental generation costs of each Portfolio option over the 20-year planning period and the Forecast LCOE (levelized cost of energy over project life)<sup>32</sup>.

- LNG Transition Portfolios have a much lower PV cost and Forecast LCOE than Default Diesel.
  - LNG Portfolio PV costs at 65-66% of PV costs for Default Diesel Portfolio.
  - LNG Forecast LCOE at 47-51% of Default Diesel Portfolio Forecast LCOE (61-66% if compare only with diesel fuel and O&M costs).
- LNG Transition Portfolios have a much lower PV cost and Forecast LCOE than any of the Minimum GHG Portfolio Options.
  - Minimum GHG Portfolio PV costs 110-120% of PV costs for Default Diesel Portfolio.
  - Minimum GHG Portfolio Forecast LCOE at 80-109% of Default Diesel Portfolio Forecast LCOE (104-141% if compare only with diesel fuel and O&M costs).

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<sup>31</sup> The Wood Biomass resource option is typically assumed to operate year round – however, it is assumed to be flexible enough to shut down when grid annual load drops to very low levels after 2020 (as a result, the material O&M cost of \$72.8/MW.h (2010\$) is saved, providing this option with PV cost savings relative to other Minimum GHG resource options which do not have this flexibility).

<sup>32</sup> PV cost and LCOE assume discount rate of 6.56%/year based on YEC's 2009 GRA approved return on equity and cost of new long-term debt. PV cost excludes assumed \$35.4 million PV cost for DSM/SSE over this period, which is common to all Portfolio options. Forecast LCOE for a specific resource option is cents per kW.h of forecast diesel displaced [2010\$] over the assumed economic life of that resource option and assuming forecast diesel generation under Scenario A with DSM/SSE.

**Table 6-1: Overview of Resource Portfolio Near-Term Options Scenario A with DSM/SSE: 2011-2030**

|  | PV Cost<br>million <sup>1</sup> | Forecast<br>LCOE <sup>2</sup> | Capital Cost<br>(2010\$) | O&M Cost<br>(2010\$)     | Reliable<br>Capacity | Total<br>Capacity | Energy<br>Capability | Diesel<br>Required/<br>Displaced |
|--|---------------------------------|-------------------------------|--------------------------|--------------------------|----------------------|-------------------|----------------------|----------------------------------|
|  | (2010\$)                        | c/kWh                         | \$/MW \$million          | \$/MW.h \$mill./<br>year | MW                   | MW                | GW.h/year            | 2015-19<br>av.<br>GW.h/yr        |
| <b>Default Diesel Portfolio</b>            |                                 |                               |                          |                          |                      |                   |                      |                                  |
| Diesel Energy                              | 133.9                           | 28.0                          |                          | 280.3                    | -                    |                   | 292.0                | 85                               |
| Diesel Capacity                            | 34.7                            | 8.1                           | 1.5                      | 55.6                     |                      | 37.1              | 37.1                 |                                  |
| Total Default Diesel                       | <b>168.6</b>                    | <b>36.1</b>                   |                          |                          |                      |                   |                      |                                  |
| <b>Min GHG Portfolio Options</b>           |                                 |                               |                          |                          |                      |                   |                      |                                  |
| <b>Marsh &amp; 15 MW Wood Biomass</b>      |                                 |                               |                          |                          |                      |                   |                      |                                  |
| Marsh Lake Storage                         | 7.0                             | 34.8                          |                          | 10.5                     | -                    | 0.1               | 1.0                  | 6.7                              |
| Wood Biomass (15 MW)*                      | 121.8                           |                               | 5.7                      | 85.5                     | 72.8                 | 4.0               | 15.0                 | 120.0                            |
| Diesel Energy                              | 39.7                            |                               |                          |                          | 280.3                |                   |                      | 166.4                            |
| Diesel Capacity                            | 16.5                            |                               | 1.5                      | 31.6                     |                      | 21.1              | 21.1                 |                                  |
| Total                                      | <b>185.0</b>                    |                               |                          | 127.6                    |                      | 37.1              | 37.1                 |                                  |
| *No O&M after 2020                         |                                 |                               |                          |                          |                      |                   |                      |                                  |
| <b>Marsh, Gladstone &amp; 21 MW Wind</b>   |                                 |                               |                          |                          |                      |                   |                      |                                  |
| Marsh Lake Storage                         | 7.0                             | 29.0                          |                          | 10.5                     | 0.1                  | 1.0               | 1.0                  | 6.7                              |
| Gladstone Diversion                        | 20.8                            |                               |                          | 40.0                     | 0.2                  | -                 | -                    | 36.6                             |
| Wind (21 MW)*                              | 88.4                            |                               | 3.6                      | 93.4                     | 2.1                  | 5.0               | 26.0                 | 55.6                             |
| Diesel Energy                              | 57.1                            |                               |                          |                          | 280.3                |                   |                      | 245.3                            |
| Diesel Capacity                            | 27.3                            |                               | 1.5                      | 46.6                     |                      | 31.1              | 31.1                 |                                  |
| Total                                      | <b>200.6</b>                    |                               |                          | 190.5                    |                      | 37.1              | 58.1                 |                                  |
| *Includes 5MW DRUPS                        |                                 |                               |                          |                          |                      |                   |                      |                                  |
| <b>Marsh, 21 MW Wind, &amp; 2.2 MW WTE</b> |                                 |                               |                          |                          |                      |                   |                      |                                  |
| Marsh Lake Storage                         | 7.0                             | 39.4                          |                          | 10.5                     | 0.1                  | 1.0               | 1.0                  | 6.4                              |
| Wind (21 MW)*                              | 88.4                            |                               | 3.6                      | 93.4                     | 2.1                  | 5.0               | 26.0                 | 55.6                             |
| 2.2 MW Waste to Energy (WTE)               | 25.9                            |                               | 17.7                     | 39.0                     | (0.3)                | 2.2               | 2.2                  | 17.1                             |
| Diesel Energy                              | 56.7                            |                               |                          |                          | 280.3                |                   |                      | 228.0                            |
| Diesel Capacity                            | 24.6                            |                               | 1.5                      | 43.3                     |                      | 28.9              | 28.9                 |                                  |
| Total                                      | <b>202.6</b>                    |                               |                          | 186.2                    |                      | 37.1              | 58.1                 |                                  |
| *Includes 5MW DRUPS                        |                                 |                               |                          |                          |                      |                   |                      |                                  |
| <b>LNG Transition Portfolio Options</b>    |                                 |                               |                          |                          |                      |                   |                      |                                  |
| <b>Marsh &amp; 22 MW LNG</b>               |                                 |                               |                          |                          |                      |                   |                      |                                  |
| Marsh Lake Storage                         | 7.0                             | 17.1                          |                          | 10.5                     | 0.1                  | 1.0               | 1.0                  | 6.4                              |
| LNG (22 MW)                                | 65.4                            |                               | 1.8                      | 40.3                     | 95.6-107.9           | 0.1               | 22.0                 | 173.4                            |
| Diesel Energy                              | 29.2                            |                               |                          |                          | 280.3                |                   |                      | 111.2                            |
| Diesel Capacity                            | 10.6                            |                               | 1.5                      | 21.1                     |                      | 14.1              | 14.1                 |                                  |
| Total                                      | 112.1                           |                               |                          | 71.9                     |                      | 37.1              | 37.1                 |                                  |
| <b>LNG (22 MW)</b>                         |                                 |                               |                          |                          |                      |                   |                      |                                  |
| LNG (22 MW)                                | 69.0                            | 18.4                          | 1.8                      | 40.3                     | 95.6-107.9           | 0.1               | 22.0                 | 173.4                            |
| Diesel Energy                              | 29.2                            |                               |                          |                          | 280.3                |                   |                      | 119.1                            |
| Diesel Capacity                            | 11.4                            |                               | 1.5                      | 22.6                     |                      | 15.1              | 15.1                 |                                  |
| Total                                      | 109.6                           |                               |                          | 62.9                     |                      | 37.1              | 37.1                 |                                  |

Notes: 1. PV = Present Value cost over 20-year planning period (2011-2030). Excludes \$35.4 million PV cost for DSM/SSE.  
2. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010\$]) over project life.

The LNG resource option has much lower incremental capital costs than the wood biomass or wind resource options examined, and much lower capital costs per MW than each of the Minimum GHG resource options. LNG, WTE and Wood Biomass resource options each provide reliable capacity equal to their plant capacity – in contrast, Wind and Gladstone each provide little if any reliable capacity benefits.

### **Comparative Rate Impacts for Near-Term Portfolio Options**

The Default Diesel Portfolio shows material increases in grid diesel energy requirements by 2015 under all load scenarios. Assuming DSM/SSE, diesel fuel and O&M cost increases from 2011 to 2015 are projected at \$4.3 million with Base Case loads, \$25.9 million with Scenario A loads and \$43.8 million with Scenario B loads (see Figure 5-1 and accompanying table). Increased revenues from new loads will offset some, but not all, of these increased costs - resulting in upward pressure on rates.

Unlike the Default Diesel Portfolio, LNG portfolio options allow major new incremental loads to occur by 2015 under Scenario A or B without requiring material rate increase impacts. As reviewed in Figure 6-2, average annual costs in 2015 with Scenario A loads and DSM/SSE are projected at 17 cents/kW.h with LNG (including capital costs) as compared to 29 cents/kW.h with diesel (fuel and O&M costs, excluding capital costs).

The Minimum GHG Portfolio options show varying rate impacts during 2015-2020 depending on the assumed load scenario. Overall, however, costs for these options during 2015-2019 are at best only slightly lower than diesel - and in several instances are higher than diesel fuel and O&M costs (see Figure 6-2).

After 2020 with Scenario A or B and DSM/SSE, the assumed drop in grid loads (when mine loads are forecast not to be connected, based on the then available information) at the outset could slightly reduce Default Diesel Portfolio rate impacts, but ongoing load growth by 2030 would lead to renewed rate increase pressures<sup>33</sup>. After the loss of the mine loads, LNG Transition Portfolio Options would continue to have lower rate impacts than any of the other non-diesel portfolio options - however, until later in the period (close to 2030) the Default Diesel Portfolio with these greatly reduced loads could have slightly lower rate impacts than the LNG Transition Portfolio Options<sup>34</sup>.

A sensitivity test assuming connected mine loads continue to 2030 at sufficient levels to prevent a drop in grid diesel generation under the Default Diesel Portfolio indicates that the least cost LNG Transition

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<sup>33</sup> Loss of mine loads leads to loss of all revenues from these loads, as well as reduced diesel costs as shown in Figure 5-1. All Portfolio Options, including Default Diesel, include assumed costs for DSM/SSE as well as capacity installed that are not reduced by mine load reductions.

<sup>34</sup> In cases with no DSM/SSE, the LNG Transition Portfolio Options would have lower rate impacts than Default Diesel in all years of the planning period (as well as lower rate impacts than any of the Minimum GHG Portfolio Options).

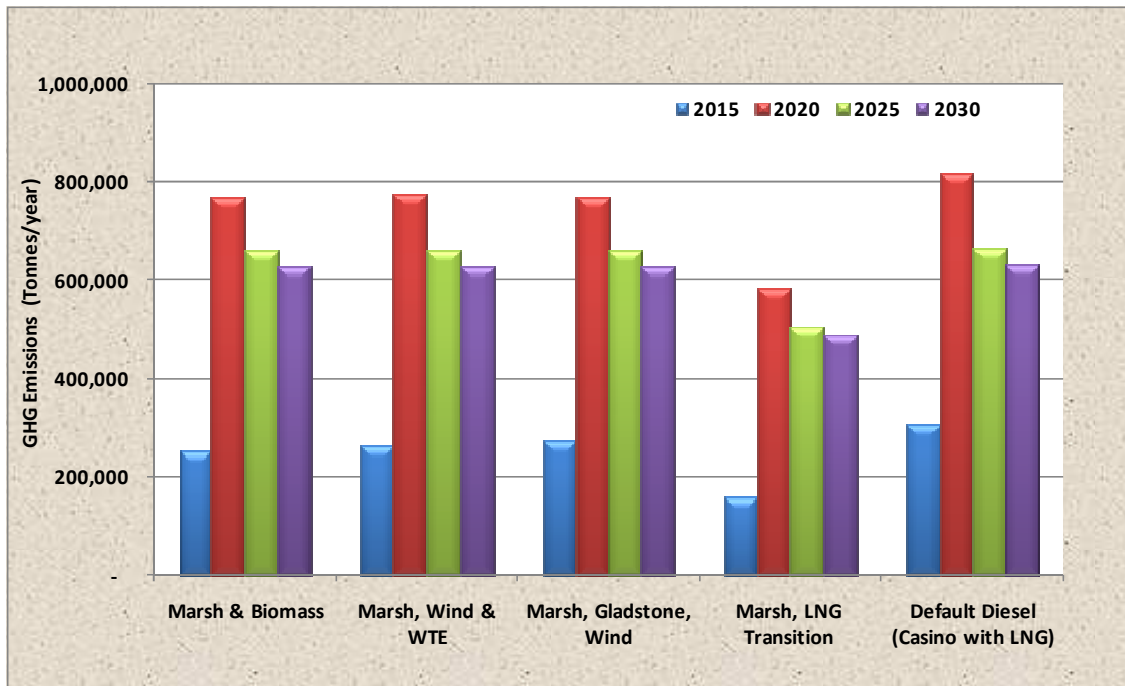
Portfolio Option continues through 2030 to show potential rate impacts that are materially lower than the potential rate impacts for all Minimum GHG Portfolio Options as well as the Default Diesel Portfolio.

**Comparative GHG Emission Impacts for Near-Term Portfolio Options**

LNG is the only non-diesel portfolio option examined for the near-term that can be used off-grid to reduce reliance on diesel (i.e., either off-grid communities or industrial customers).

Figure 6-5 demonstrates that when off-grid industrial and utility diesel community load opportunities are fully considered, near-term LNG supply development in Yukon as part of the LNG Transition approach has the potential to achieve far lower overall GHG emission levels from power generation in Yukon during the next 5-10 years than can be secured by grid-focused Minimum GHG Emissions Portfolio Options.

**Figure 6-5: Portfolio Option Yukon GHG (tonnes/year) – 2015-2030  
Grid Scenario A with DSM/SSE, Off-grid Diesel Community, & Off-Grid Mines**



**Total Yukon GHG Emissions (Tonnes/Year)<sup>1</sup>**

|                                    | 2015    | 2020    | 2025    | 2030    |
|------------------------------------|---------|---------|---------|---------|
| Marsh & Biomass                    | 252,384 | 767,010 | 661,267 | 625,287 |
| Marsh, Wind & WTE                  | 263,266 | 775,226 | 661,267 | 625,287 |
| Marsh, Gladstone, Wind             | 270,569 | 769,132 | 661,267 | 625,287 |
| Marsh, LNG Transition <sup>2</sup> | 158,844 | 582,266 | 505,355 | 488,089 |
| Default Diesel (Casino with LNG)   | 306,067 | 815,235 | 662,522 | 630,560 |

1. Grid Scenario A with DSM/SSE, Off Grid Diesel Communities, & Off Grid Mines

2. Assumes LNG simple cycle at Watson Lake, LNG combined cycle at all mines.

The specified resource portfolios are examined in Figure 6-5, with any requirements not met by the specified resources assumed to be supplied by diesel generation under each portfolio. LNG is the only resource option other than diesel that can be applied in the near-term to off-grid as well as on grid requirements. The analysis excludes potential LNG impacts to reduce diesel and oil products in Yukon transportation and heating end uses (the largest GHG generating sectors in Yukon today).

- Yukon GHG emissions are materially lower in each time period with LNG than with any other resource option; reflects ability to apply LNG to off-grid diesel displacement.
- Overall LNG accessibility for all potential Yukon uses is facilitated by co-ordinated near-term planning and actions.

## 7.0 LONGER-TERM RESOURCE OPTIONS TO DEFAULT DIESEL

### Greenfield Hydro Opportunities

A range of greenfield hydro resource project opportunities are potentially available to start construction before 2021, subject to appropriate planning and development of loads sufficient to fully utilize these resources<sup>35</sup>. 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.

Table 7-1 summarizes the available hydro sites by size of project, indicating key features as currently estimated (potential installed capacity, annual energy, capital cost and levelized lifecycle cost at full utilization)<sup>36</sup>. Total potential supply exceeds 6,800 GW.h/year at full utilization levelized cost (including transmission) below 15 cents per kW.h.

- **Hydro Options at less than 10 cents/kW.h** – Nine sites or schemes are identified with estimated Full Utilization LCOE's (2009\$) below 10 cents per kW.h and over 4,390 GW.h per year of average annual sustainable energy (net of duplication among sites); four of these sites are Medium scale (11-60 MW) that could together provide over 850 GW.h/year; the other sites are Large scale (>60 MW).
- **Hydro Options at 10-15 cents/kW.h** – A further eight sites or schemes are identified with Full Utilization LCOE's between 10 and 15 cents per kW.h and over 2,000 GW.h of additional average annual sustainable energy; five of these sites are Medium scale (over 850 GW.h/year); the other sites are Large scale (>60 MW).
- **Other Medium Scale Hydro Options** – A further two Medium scale sites located north of the Watson Lake area are identified with Full Utilization LCOE's under 15 cents per kW.h if exceptionally high transmission cost estimates to connect to the existing grid are excluded from consideration. Together, these sites could provide over 375 GW.h per year of additional average annual sustainable energy.

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<sup>35</sup> The geothermal option is identified in the 2011 Resource Plan as "other long-term options" in Yukon that might provide both low cost and low GHG emissions at some point during the planning period – however, beyond monitoring of related activities (e.g., geothermal exploration and confirmation drilling), the 2011 Resource Plan does not consider specific planning activities for the next five years. Similarly, monitoring of ongoing activities is all that is considered today with regard to potential development in the future of a natural gas pipeline, Eagle Plains gas, or transmission connection to the BC grid and/or Alaska.

<sup>36</sup> See Figure 1-2 for map showing the location of identified load and resource supply options.

Development of such longer-term renewable resource options is subject to connecting new grid loads that could fully utilize the specific resource options over 20-30 or more years.

- Potential off-grid mine developments prior to 2021 relying on fossil fuel generation are identified that could potentially exceed 1,500 GW.h/year and remain above 1,300 GW.h/year through 2045 in the event that three of these multi-decade off-grid mines are developed, i.e., the Casino Property west of the CSTP grid (940 GW.h/year), the Selwyn project located to the east of the WAF grid in the passes close to the border with NWT (147 GW.h/year), and the Northern Dancer project located near the Alaska Highway east of Teslin (200-300 GW.h/year).
- If the Alaska Highway Pipeline project proceeds, gas compressors for this project could potentially add 1,470 GW.h/year of additional equivalent energy requirements (six compressor stations) by approximately 2020/21 that would also be sustained over 25 years in the event that GHG emissions concerns support electrification initiatives.

Table 7-2 identifies potential off-grid mine loads and/or pipeline compressor loads that could radically change the electricity generation sector in Yukon during the next 5 to 10 years. These potential new loads offer the opportunity to plan for new legacy hydro development opportunities concurrent with actual development of new major mines or other major new loads. The following possible development packages are noted:

- **Develop Southern Lakes Grid Connection** – These are not low cost options; development of some of these options might be considered if Gladstone is not able to proceed and loads remain uncertain.
- **Develop Grid East of Ross River** – Potential options to consider in connection with Selwyn/Mactung mine loads, which offer 20+ years of load.
- **Develop Southern Grid to East Near Alaska Highway** – Potential options to consider in connection with Northern Dancer mine load and/or Alaska Highway Pipeline compression loads which offer 20+ years of load.
- **Develop Central & Western Yukon Grid** – Potential options to consider in connection with Casino and other mine loads south of Dawson City, which offer 20+ years of load.

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. Figure 7-1 sets out proposed planning activities that would need to be pursued during the next five to ten years to protect the ability to start construction prior to 2021.

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### **Coordination with LNG Transition Portfolio Option**

The LNG Transition Portfolio Option is a near-term rather than a long-term legacy resource option for Yukon. The intent is 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 options so as to secure Forecast Utilization LCOEs that are equivalent to or less than LNG costs.

LNG Transition Portfolio Options are expected to show escalating costs as natural gas prices increase at a rate faster than general inflation. By 2020, the initial year costs for a new hydro development with a levelized cost (2010\$) of 10 cents/kW.h might potentially correspond to the then current costs for LNG-supplied generation - in which case, subject to securing sufficient long-term load, the transition from LNG to new hydro could occur relatively smoothly<sup>37</sup>.

At such time as new hydro develops, LNG grid generating unit capacity no longer needed for baseload energy generation can be retained for peaking, low water and emergency/grid reliability use. These units are flexible as to the range of such uses - and will likely be dual fuel in nature such that they can also use diesel fuel if so required. Furthermore, when new hydro is developed LNG supplies are expected to continue to be provided in Yukon to meet remaining off-grid power loads as well as other sector loads such as transportation<sup>38</sup>. Introduction of LNG/natural gas supplies in Yukon will also likely create longer-term development of natural gas use in the transportation and heating sectors.

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<sup>37</sup> Figure 6-2 shows annual costs per kW.h during the period of forecast connected mine loads (2015-2020), indications that LNG annual costs (with capital) during this period remain well below annual costs for all renewable options other than the hydro enhancement options (Marsh Lake Storage and Gladstone Diversion) - by 2020, LNG costs in escalated dollars approximate 19 c/kW.h (13 cents for fuel and O&M only).

<sup>38</sup> These same considerations apply in the event that natural gas supplies come to be available directly in Yukon through the Alaska Highway Pipeline Project and/or Eagle Plain gas development. LNG liquefaction facilities may need to be moved to (or developed in) Yukon - but ongoing LNG requirements are anticipated to remain for off-grid power uses and other sectors.

**Table 7-1: Summary of Potential Hydro Sites**

|  |   | Installed Capacity (MW) | Annual Energy (GWh) | Capital Cost (Million \$2009) | Levelized Cost (c/kWh) |
|--|---|-------------------------|---------------------|-------------------------------|------------------------|
| <b>Small Hydro Projects (&lt;10MW)</b>   |   |                         |                     |                               |                        |
| 20-23 c/kWh                              | Moon Lake   | 5.8                     | 32.9                | 126.8*                        | 19.9                   |
|  | Tutshi River  | 4.2                     | 30.3                | 135.5*                        | 23.1                   |
|  | Tutshi (Windy Arm)                                    | 5.9                     | 39.4                | 164.9*                        | 21.6                   |
|  | Pine Creek at Atlin                                   | 3.5-8                   | 23-52               | NA                            | NA                     |
| <b>Medium Hydro Projects (&lt;60 MW)</b> |   |                         |                     |                               |                        |
| < 10 c/kWh                               | Hoole Canyon with Storage                             | 40.4                    | 275                 | 460.1                         | 8.6                    |
|  | Granite Canyon Small                                  | 60.0                    | 400                 | 670.3                         | 8.7                    |
|  | Slate Rapids  | 41.6                    | 266                 | 505.6                         | 9.8                    |
|  | Finlayson   | 17.0                    | 128.9               | 233.7**                       | 9.4                    |
| 10 to 15 c/kWh                           | Ross Canyon   | 30                      | 181                 | 495.0                         | 14.1                   |
|  | False Canyon  | 58                      | 370                 | 1,036.3**                     | 14.5                   |
|  | Two Mile Canyon                                       | 53.1                    | 280                 | 696.5                         | 12.9                   |
|  | Combined Slate Rapids <sup>1</sup> & Hoole            | 50.1                    | 351.1               | 728.9                         | 10.7                   |
|  | Slate Rapids <sup>1</sup> (powerhouse at foot of dam) | 22.3                    | 156.3               | 441.4                         | 14.6                   |
| Other <sup>2</sup>                       | Middle Canyon   | 38.0                    | 200                 | 773.5***                      | 20.0                   |
|  | Upper Canyon  | 25.2                    | 176.6               | 677.2***                      | 19.8                   |
| <b>Large Hydro Project (&gt;60 mW)</b>   |   |                         |                     |                               |                        |
| < 10 c/kWh                               | Granite Canyon High                                   | 254.0                   | 1,783               | 1,680.7                       | 4.9                    |
|  | Fraser Falls Low                                      | 100.0                   | 700                 | 1,340.4                       | 9.9                    |
|  | Granite Canyon Low                                    | 80.0                    | 600                 | 934.8                         | 7.3                    |
|  | Fraser Falls High                                     | 300.0                   | 2,100               | 2,540.6                       | 6.3                    |
|  | Combined Slate Rapids & Hoole                         | 69.4                    | 459                 | 849.7*                        | 9.6                    |
| 10 to 15 c/kWh                           | Detour Canyon   | 65.0                    | 435                 | 1,057.0                       | 12.6                   |
|  | Detour Canyon w storage At Pelly Lakes                | 100.0                   | 585                 | 1,301.0                       | 11.5                   |
|  | Liard Canyon  | 93.5                    | 659                 | 1,554.6**                     | 12.2                   |

Notes:

1. Powerhouse at foot of dam
  2. Excluding exceptionally high transmission costs to connect to existing grid, these sites would be under 15 cents per kW.h
- \* Transmission costs to connect to grid are 18% of cost for Tutshi (Windy Arm), 21% of cost for Combined Slate Rapids & Hoole Canyon, and 26-27% of cost for Moon Lake & Tutshi River.
- \*\* Transmission costs are 33% of cost for Liard Canyon, 36% of cost for Finlayson, and 38% of cost for False Canyon.
- \*\*\* Transmission costs to connect to existing grid are estimated at 54-55% of cost for these sites.

**Table 7-2: Yukon Industrial Load Opportunities and Potential Hydro Sites**

| POTENTIAL INDUSTRIAL LOAD OPPORTUNITIES  |  | POTENTIAL HYDRO DEVELOPMENT OPPORTUNITIES                                    |                               |  |       |      |
|--|--|--|-------------------------------|--|-------|------|
| <p><i>Developing low cost/low emission hydro options depends on connecting new grid loads that could adequately utilize the resource for 20-30 years</i></p> <p><b>DEVELOP SOUTHERN LAKES GRID CONNECTIONS</b></p> <p><i>Timing for development of these projects in the next decade will depend on whether or not Gladstone is developed, future grid loads and definition of distinct hydro project opportunities</i></p> <p><b>DEVELOP GRID TO EAST OF ROSS RIVER</b></p> <p><b>SELWYN</b> (147 GWh/yr) &amp; <b>MACTUNG</b><br/>30+ year load in service 2014/15 - A medium hydro project in the 17-30 MW range (129 to 181 GWh/yr) to the east of the northern WAF grid could match all or most of the Selwyn load</p> <p><b>DEVELOP SOUTHERN GRID TO EAST NEAR ALASKA HWY</b></p> <p><b>NORTHERN DANCER</b> (200-300 GWh/yr) - a 30 year load in service in 2017 to east of Teslin. A medium hydro project to serve this load could provide basis for extension of grid in south-east portion of Yukon</p> <p><b>PIPELINE COMPRESSOR</b> - Marsh Lake - 245 GWh/yr load per compressor in service in 2020/21 - Could provide anchor load for a medium hydro project in 266-280 GWh range (25 year load)</p> <p><b>PIPELINE COMPRESSOR</b> - Alaska Hwy - 245 GWh/yr load per compressor in service in 2020/21; May provide an opportunity to develop sites and transmission in east Yukon such as Liard Canyon (25 year load); Liard Canyon may also support development of NORTHERN DANCER</p> <p><b>DEVELOP CENTRAL &amp; WESTERN YUKON GRID</b></p> <p><b>CASINO MINE</b> (940.8 GWh/yr)<br/>20-30 year load in service in 2018-19 - A large hydro project in the 69-100 MW range (450-700 GWh/yr) reasonably near the CSTP grid could match a large share of the Casino Load</p> |  | Installed Capacity (MW)  | Annual Energy (GWh)           | Levelized Cost (c/kWh)                 |       |      |
|  |  |  |                               | <b>Small Hydro Projects (&lt;10MW)</b> |       |      |
|  |  | <b>Southern Lakes Projects</b>   |                               |  |       |      |
| }  |  | 20-23 c/kWh  | Moon Lake                     | 5.8                                    | 32.9  | 19.9 |
|  |  |  | Tutshi River                  | 4.2                                    | 30.3  | 23.1 |
|  |  |  | Tutshi (Windy Arm)            | 5.9                                    | 39.4  | 21.6 |
|  |  |  | Pine Creek at Atlin           | 3.5 to 8                               | 23-52 | N/A  |
|  |  | <b>Medium Hydro Projects (&lt;60 MW)</b>                                     |                               |  |       |      |
| }  |  | < 10 c/kWh   | Hoole Canyon with Storage     | 40.4                                   | 275   | 8.6  |
|  |  |  | Slate Rapids                  | 41.6                                   | 266   | 9.8  |
|  |  |  | Finlayson                     | 17                                     | 128.9 | 9.4  |
|  |  | 10-15 c/kWh  | Ross Canyon                   | 30                                     | 181   | 14.1 |
|  |  | <b>Medium Hydro Projects (&lt;60 MW)</b>                                     |                               |  |       |      |
| }  |  | 10 to 15 c/kWh   | False Canyon                  | 58                                     | 370   | 14.5 |
|  |  |  | Middle Canyon*                | 38                                     | 200   | 20.0 |
|  |  |  | Upper Canyon*                 | 25.2                                   | 176.6 | 19.8 |
|  |  |  | Two Mile Canyon               | 53.1                                   | 280   | 12.9 |
|  |  | 8.7 10 to 15 c/kWh   | Combined Slate Rapids & Hoole | 50.1                                   | 351.1 | 10.7 |
|  |  |  | Granite Canyon Small          | 60                                     | 400   | 8.7  |
|  |  |  | Slate Rapids                  | 22.3                                   | 156.3 | 14.6 |
|  |  | <b>Large Hydro Project (&gt; 60 MW)</b>                                      |                               |  |       |      |
|  |  | 10-15 c/kWh  | Liard Canyon                  | 93.5                                   | 659   | 12.2 |
|  |  | *Transmission costs to connect to existng grid are 54-55% of levelized cost. |                               |  |       |      |
|  |  | <b>Large Hydro Project (&gt; 60 MW)</b>                                      |                               |  |       |      |
| }  |  | < 10 c/kWh   | Granite Canyon Low            | 80                                     | 600   | 7.3  |
|  |  |  | Fraser Falls Low              | 100                                    | 700   | 9.9  |
|  |  |  | Granite Canyon High           | 254                                    | 1783  | 4.9  |
|  |  |  | Fraser Falls High             | 300                                    | 2100  | 6.3  |
|  |  |  | Combined Slate Rapids & Hoole | 69.4                                   | 459   | 9.6  |
|  |  | 10 to 15 c/kWh   | Detour Canyon                 | 65                                     | 435   | 12.6 |
|  |  |  | Detour Canyon w storage       | 100                                    | 585   | 11.5 |



## 8.0 SUMMARY CONCLUSIONS & RECOMMENDED PLANS

### Overview of Options

Figure 8-1 summarizes near-term options examined in the 2011 Resource Plan in the context of Yukon Energy's four key planning principles. Conservation/efficiencies (DSM/SSE) programs are being developed as an option to be pursued in combination with other selected resource options.

**Figure 8-1: Near-Term Resource Supply Options<sup>39</sup>**

| <b>OPTIONS</b>                                | <b>Reliability</b><br>Winter Peak Capacity;<br>Development Timing & Cost | <b>Affordability</b><br>Potential lifecycle cost per kWh if fully used | <b>Flexibility</b><br>Ratepayer Risk re: Mine Load Reductions | <b>Environmental Responsibility</b><br>Env. Mitigation; GHG Emission Reduction |
|---|--|--|---|--|
| Southern Lakes (Marsh Lake) Hydro Enhancement | Medium   | High   | Medium  | High   |
| Gladstone Diversion Hydro Enhancement         | Medium   | High   | Medium  | High   |
| Conservation / Efficiencies                   | Medium   | High   | Medium  | High   |
| Biomass                                       | High   | Medium   | Low   | High   |
| Liquefied Natural Gas                         | High   | Medium-High  | High  | Medium   |
| Wind  | Low  | Medium   | Low   | High   |
| Diesel  | High   | Low  | High  | Low  |

Table 8-1 provides an overview of the near-term resource options identified for potential construction start on the grid before 2015 (including a 3 MW wood biomass pilot plant option<sup>40</sup>), and the longer term resource options identified for potential construction start before 2021. The Gladstone Diversion project is excluded from the near-term options on the basis that construction start is not feasible before 2015, and

<sup>39</sup> See Table 4-1 for more detail.

<sup>40</sup> The 2011 Resource Plan examined various wood biomass plant options, ranging from 10 MW to 25 MW and at different locations to accommodate potential wood biomass supply (e.g., Whitehorse for 25 MW plant; 10 to 15 MW plant in Minto burn area option). Based on feedback from the workshop held on wood biomass, this option has been scaled back to a 2-3 MW wood biomass pilot plant option. Yukon Energy is currently developing a partnership with the Champagne and Aishihik First Nations and Dakwakada Development Corporation to examine opportunities for a small-scale (2-3 MW) wood biomass pilot project, potentially with existing wood operations at Haines Junction, and to seek funding support for this pilot plant.

earliest in-service is in late 2017. Table 8-2 provides a more detailed overview of the near-term resource option capabilities and costs under both Scenario A and B grid loads with DSM/SSE.

In the near-term, LNG is identified in the 2011 Resource Plan as the only near-term option that can totally displace Default Diesel on the grid during 2015-2019 with forecast Scenario A or B loads (e.g., with forecast diesel generation ranging from 85 to 143 GW.h/year with DSM/SSE). Excluding the relatively small energy impact Marsh Lake Storage hydro enhancement option (approximately 6 GW.h/year), LNG is also the lowest cost near-term option, with costs per kW.h of diesel displaced less than half the cost of diesel. Wood Biomass ranks second behind LNG in diesel displacement capability, but is the highest cost near-term option (with costs per kW.h of diesel displaced higher than the cost of diesel). The only other near-term option with potential ability to displace more than 50% of Scenario A diesel generation requirements (i.e., Wind) has 2015-2019 costs per KWh only slightly lower than diesel, and forecast LCOE costs that are higher than diesel under Scenario A or B loads with the assumed DSM/SSE.

In contrast to the near-term options, longer term hydro options are identified in the 2011 Resource Plan that offer a wide range of annual energy capability (e.g., options in Table 8-1 range from 33 to over 450 GW.h/year), with several options also having estimated Full Utilization LCOE at less than 10 cents/kW.h. The 2011 Resource Plan outlines the requirements for successful development of these longer term options, including securing appropriate long-term loads as required to adequately utilize such options over 20-30 or more years and sustaining sufficient and successful site specific planning processes over the next five years to protect the ability for potential construction start before 2021.

Tables 8-1 and 8-2 also show the extent to which each near-term resource option's economic feasibility (i.e., comparative LCOE) is affected by the option's flexibility to adapt to Yukon's isolated grid and the expected range of load and hydro generation conditions on this grid.

- LNG, Wood, Wind and Waste-to-Energy options, for example, show minimal variation in estimated LCOE when full utilization is simply assumed of all electricity generated for each option, e.g., LCOEs (2010\$) for these options range from 12 c/kW.h for LNG to 17 c/kW.h for the 3 MW Wood Pilot.
- However, when Scenario A forecast loads (which are well in excess of Base Case loads) and expected hydro conditions on Yukon's isolated grid are considered, LNG is the only option with an LCOE at less than 20 c/kW.h for diesel displaced, and the 3 MW Wood Pilot is the only other option with an LCOE less than diesel fuel and O&M cost at 28 c/kW.h. Higher LCOEs for Wind, 15 MW Wood Biomass and 2.2 MW Waste-to-Energy options in this instance reflect relative

inflexibility to adapt to an assumed sharp drop in mine loads on the grid after 2020 as well as seasonal and annual variability in hydro generation on the grid.

### **LNG Transition Option Near-Term Benefits**

In summary, the 2011 Resource Plan indicates that the LNG Transition Portfolio option provides a range of potential benefits relative to the other near-term grid generation options available for potential commitment before 2015:

- LNG is superior to diesel in terms of cost (affordability) and emissions (environmental responsibility); relative to near-term renewable resource options, LNG is less costly while also providing high reliability, flexibility and diversity of potential Yukon uses on and off-grid.
- 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 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 is the only option to offer material reductions in near-term rate increase impacts relative to diesel under Scenario A or B loads, as well as the non-diesel option with the lowest rate impacts in the event that currently assumed 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 is the only option to offer opportunity to reduce present value diesel costs during the planning period under Scenarios A and B (projected reductions at 35% under Scenario A and 41% under Scenario B).
  - Overall, LNG offers high flexibility with ability to be turned off and ability to accommodate load changes; it can provide cost effective baseload generation and backup capacity, and can 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).

In order to pursue the LNG option for near-term development for power generation in Yukon by late 2014, Yukon Energy is pursuing further feasibility work 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 being pursued 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).

### **Resource Portfolios - Combining Options**

Combining projects on the Yukon grid can dilute the benefits and raise LCOEs relative to what is shown for individual options.

For example, the Scenario A (with DSM/SSE) LCOE is 11.4 c/kW.h for Marsh Lake storage on its own and 8.0 c/kW.h for Gladstone Diversion on its own (see Table 8-1) - however, combining these two hydro enhancement projects results in a higher overall LCOE at 13.1 c/kW.h for the combined projects.

Similarly, LCOEs (2010\$) per kW.h of displaced diesel generation for various renewable resource options under Scenario A loads are significantly higher when combined with the assumed DSM/SSE than when assessed without DSM/SSE<sup>41</sup>:

- Marsh Lake Storage LCOE: 11.4 c/kW.h with DSM/SSE, 8.6 c/kW,h without DSM/SSE.
- Gladstone Diversion LCOE: 12.0 c/kW.h with DSM/SSE, 6.5 c/kW,h without DSM/SSE.
- 2.2 MW Waste to Energy: 31.5 c/kW.h with DSM/SSE, 17.6 c/kW,h without DSM/SSE.
- 3 MW Wood Pilot: 35.4 c/kW.h with DSM/SSE (with assumed shut down in 2020), 22.7 c/kW,h without DSM/SSE (no shut down).
- 15 MW Wood Biomass LCOE (with assumed shut down after 2020): 40.1 c/kW.h with DSM/SSE, 17.8 c/kW,h without DSM/SSE.

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<sup>41</sup> LNG LCOE for Scenario A also slightly reduced (18.4 c/kW.h with DSM/SSE, 14.0 c/kW.h without DSM/SSE).

- 21 MW Wind with 5 MW DRUPS: 40.0 c/kW.h with DSM/SSE, 19.6 c/kW.h without DSM/SSE.

In summary, dilution of benefits and higher LCOEs that result from combining projects highlight once again the extent to which load and hydro conditions on the isolated Yukon grid can critically affect economic assessment of resource option portfolios.

**Table 8-1: Overview of Resource Options - Capabilities and Costs**

|   | Capital<br>(2010\$<br>million) | Capacity<br>(MW)  | Energy<br>Capability<br>(Average<br>GWh/yr) | 2015-2019<br>Diesel<br>Required/<br>Displaced<br>(GWh/yr) | 2015-2019<br>Annual Costs<br>(cents/kW.h<br>diesel<br>displaced) | LCOE (2010<br>c/kWh)<br>Extend<br>Scenario A | LCOE (2010<br>c/kWh)<br>Extend<br>to 2030 | LCOE (2010 c/kWh)<br>Full Utilization |
|---|--------------------------------|---|---|---|--|--|---|---------------------------------------|
| <b>Near Term Options (able to start construction before 2015) with Scenario A Loads and DSM/SSE - Default Diesel is new capacity needed by 2030</b> |                                |   |   |   |  |  |   |                                       |
| <b>Default Diesel Requirement</b>   | 56                             | 37  | 292   | 85  | 29-31 (fuel +<br>O&M only)                                       | 28 (fuel +<br>O&M only)                      | 28 (fuel +<br>O&M only)                   | 28 (fuel + O&M<br>only)               |
| <b>Waste to Energy</b>  | 39                             | 2.2   | 17  | 14  | 27-31  | 31.5   | 19.0                                      | 13.5                                  |
| <b>Wind with 5 MW DRUPS</b>   | 93                             | 26*   | 56  | 45  | 26-29  | 40.0   | 21.3                                      | 14.8                                  |
|   |                                | *21 MW wind not firm<br>10.5 MW wind option was slightly less cost-effective at forecast loads. |   |   |  |  |   |                                       |
| <b>Marsh Lake Storage</b>   | 10                             | NA  | 6.7   | 6.4   | 15-16  | 11.4   | 8.8                                       | 8.5                                   |
| <b>25 MW Wood Biomass</b>   | 114                            | 25  | 199   | 85  | 48-51  | 55.4*  | 42.8                                      | 16.6                                  |
| <b>15 MW Wood Biomass</b>   | 86                             | 15  | 120   | 72  | 33-35  | 40.1*  | 28.8                                      | 15.8                                  |
| <b>3 MW Wood Pilot (Haines J.)</b>  | 19                             | 3   | 24  | 18  | 28-29  | 35.4*  | 24.7                                      | 17                                    |
|   |                                |   |   |   |  | *shut down after 2020                        |   |                                       |
| <b>LNG Transition</b>   | 40                             | 22  | 173   | 85  | 17   | 18.4   | 14.1                                      | 12                                    |
| <b>Long Term Options (Potential start construction before 2021)</b>   |                                |   |   |   |  |  |   |                                       |
| <b>Gladstone Diversion</b>  | 40                             | NA  | 36.6  | 29  | 14   | 12.03  | 8.0                                       | 5.7                                   |
| <b>Greenfield Hydro (examples)</b>  |                                |   |   |   |  |  |   |                                       |
| <b>Moon Lake</b>  | 127*                           | 5.8   | 32.9  | NA  | NA   | NA   | NA  | 19.9*                                 |
| <b>Hoole Canyon (w storage)</b>   | 460*                           | 40.4  | 275   | NA  | NA   | NA   | NA  | 8.6*                                  |
| <b>Slate Rapids</b>   | 506*                           | 41.6  | 266   | NA  | NA   | NA   | NA  | 9.8*                                  |
| <b>Finlayson</b>  | 234*                           | 17.0  | 129   | NA  | NA   | NA   | NA  | 9.4*                                  |
| <b>Combined Slate &amp; Hoole</b>   | 850*                           | 69.4  | 459   | NA  | NA   | NA   | NA  | 9.6*                                  |
|   | *Inc. Transmission<br>to grid  |   |   |   |  |  |   | *Inc. Transmission<br>to grid         |

**Table 8-2: Overview of Near-Term Resource Options - Capabilities and Costs: Scenario A Loads with DSM/SSE (options that could start construction before 2015 – Default Diesel Capacity is new grid capacity required before 2030)**

|   | 37 MW<br>Default<br>Diesel | 22-30 MW<br>LNG       | 15 MW<br>Wood<br>Biomass | 3 MW Wood<br>Pilot (Haines<br>Junction) | 21 MW<br>Wind and 5<br>MW DRUPS <sup>1</sup> | 2.2 MW<br>Waste-to-<br>Energy | Marsh Lake<br>Storage        |
|---|----------------------------|-----------------------|--------------------------|---|--|-------------------------------|------------------------------|
|   |                            | Sc. A vs.<br>Sc.B)    |                          |   |  |                               |                              |
| <b>Capital Cost (2010\$ million)</b>                              | 56                         | 40-55                 | 86                       | 19                                      | 93   | 39                            | 10                           |
| <b>Reliable Peak Winter Capacity Contribution (MW)</b>            | 37                         | 22-30                 | 15                       | 0                                       | 5  | 2.2                           | 1                            |
| <b>Annual Energy Supply (GW.h/year)</b>                           |                            |                       |                          |   |  |                               |                              |
| Annual Energy Capability  | 292                        | 173 - 236             | 120                      | 24                                      | 56   | 17                            | 6.7                          |
| 2015-19 Average Diesel Energy Required/Displaced                  |                            |                       |                          |   |  |                               |                              |
| Scenario A Load with DSM/SSE                                      | 85                         | 85                    | 72                       | 18                                      | 45   | 14                            | 6.4                          |
| Scenario B Load with DSM/SSE                                      | 143                        | 143                   | 93                       | 22                                      | 51   | 16                            | 6.6                          |
| Near term supply Issues/risks                                     | NA                         | LNG supply<br>BC/Alta | Wood Supply<br>Regime    | NA                                      | NA   | NA                            | Regulator<br>approval timing |
| <b>2015-19 Annual Costs (cents/kW.h diesel displaced)</b>         | (fuel+O&M)                 | (All cost)            | (All cost)               | (All cost)                              | (All cost)                                   | (All cost)                    | (All cost)                   |
| Scenario A Load with DSM/SSE                                      | 29-31                      | 17                    | 33-35                    | 28-29                                   | 26-29  | 27-31                         | 15-16                        |
| Scenario B Load with DSM/SSE                                      | 29-31                      | 16-17                 | 27                       | 24-25                                   | 24-26  | 24-27                         | 14-15                        |
| <b>2015-19 Cost Savings (% of Diesel Fuel and O&amp;M)</b>        |                            |                       |                          |   |  |                               |                              |
| Scenario A Load with DSM/SSE                                      | NA                         | 43%                   | -11%                     | 1%                                      | 4%   | 1%                            | 4%                           |
| <b>Lifecycle Cost of Energy (2010 cents/kWh diesel displaced)</b> | (fuel+O&M)                 | (All cost)            | (All cost)               | (All cost)                              | (All cost)                                   | (All cost)                    | (All cost)                   |
| Scenario A Load with DSM/SSE                                      | 28.0                       | 18.4                  | 40.1*                    | 35.4*                                   | 40.0   | 31.5                          | 11.4                         |
| Scenario B Load with DSM/SSE                                      | 28.0                       | 17.0                  | 31.6*                    | 30.0*                                   | 36.5   | 28.8                          | 11.1                         |
| Extend Scenario A 2019 load to 2030                               | 28.0                       | 14.1                  | 28.8                     | 24.7                                    | 21.3   | 19.0                          | 8.8                          |
| Full Utilization of all energy in each year                       | 28.0                       | 12                    | 15.8                     | 17                                      | 14.8   | 13.5                          | 8.5                          |
| Ability to adjust to load changes                                 | Flexible                   | Flexible              | Semi-flexible            | Semi-flexible                           | Not flexible                                 | Not flexible                  | Semi-flexible                |

\* Shut down after 2020

Note #1: 10.5 MW wind option was slightly less cost-effective at forecast loads.

## **Graphic Comparisons of Near-Term Options**

Figures 8-2, 8-3 and 8-4 compare key features of the near-term options and Gladstone Diversion under Scenario A loads with DSM/SSE, highlighting each option's comparative diesel displacement capability (GW.h/year) during 2015-2019. DSM/SSE (conservation/efficiency) option impacts as assumed in the 2011 Resource Plan are also included for broad comparison<sup>42</sup>.

Figures 8-2 and 8-3 compare lifecycle costs per kW.h (LCOE) and capital cost for each option, with Figure 8-3 showing the extent to which LCOE is reduced for each option under Scenario A if the 2019 grid loads are extended to 2030.

- Based on total capital costs (\$2010) as shown in Figures 8-2 and 8-3, the wind and large scale biomass options require considerably higher capital costs than other near-term options, and LNG provides far greater diesel displacement than any other option requiring similar capital costs.
- Based on LCOE (2010\$) for Scenario A loads with DSM/SSE as shown in Figure 8-2, near-term options with forecast lifecycle costs that are less the diesel include conservation/efficiency, hydro enhancements (Marsh Lake and Gladstone Diversion) and LNG; near-term option options with forecast lifecycle costs that are more than diesel include the biomass and wind options.
- Comparison of Figure 8-2 and 8-3 LCOE for any option highlights sensitivity to major changes in grid loads over the planning period, e.g., the wind and biomass options show significantly lower LCOE's if the 2019 grid loads are assumed to be extended to 2030.

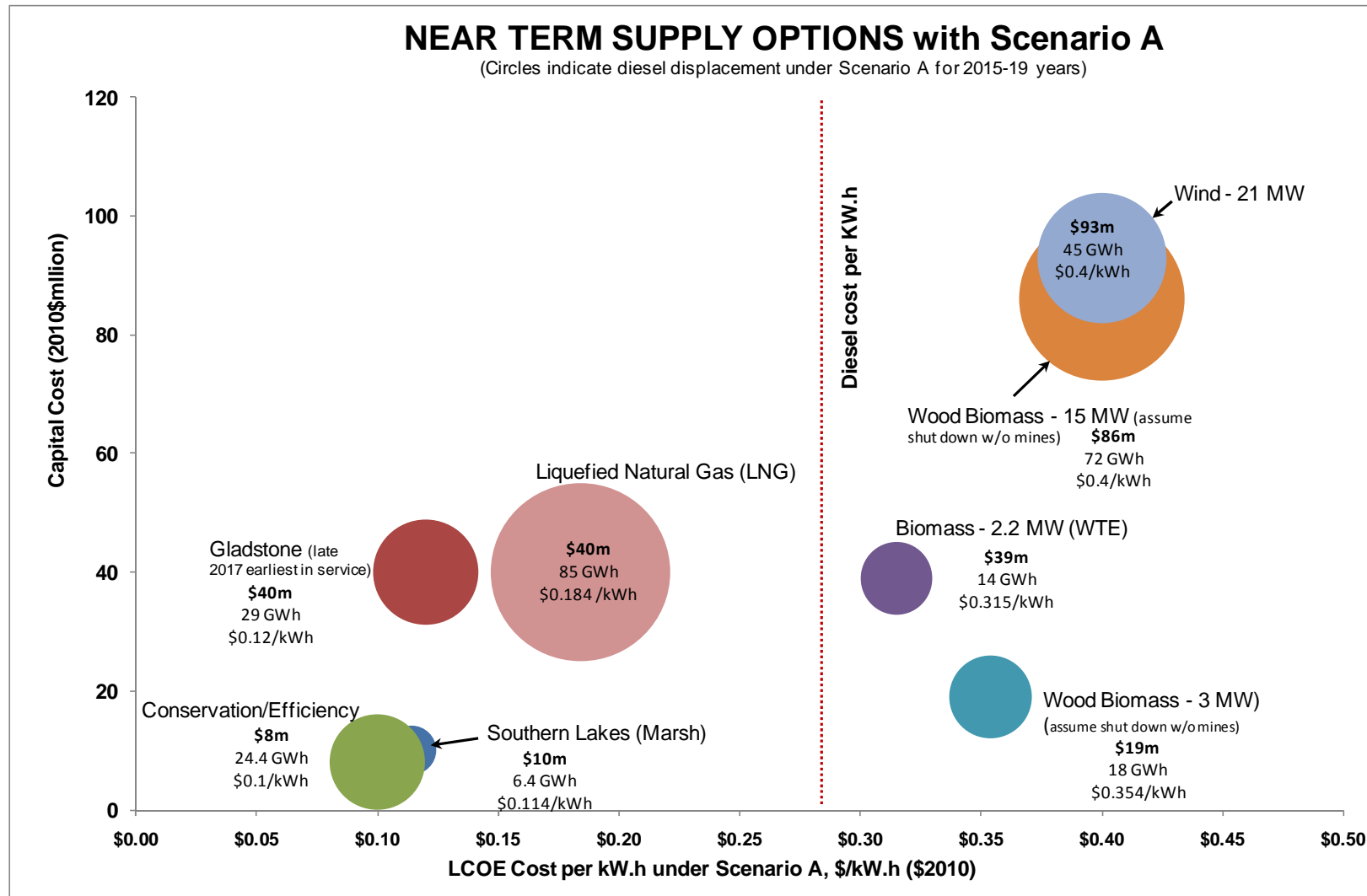
Figure 8-4 focuses on impacts in the 2015-2019 period, comparing costs per kW.h and percentage savings in diesel fuel and O&M costs for each option.

- Differences in cost per kW.h of diesel displaced for the first few years of operation (2015-19) reflect normal utility costing (e.g., capital costs charged per year decline over the project life).
- Comparative near-term diesel fuel and O&M cost savings for ratepayers reflect diesel displacement capability as well as near-term cost saving capability per kW.h relative to diesel generation for each option, and highlight LNG's overall cost saving benefits relative to other near-term options.

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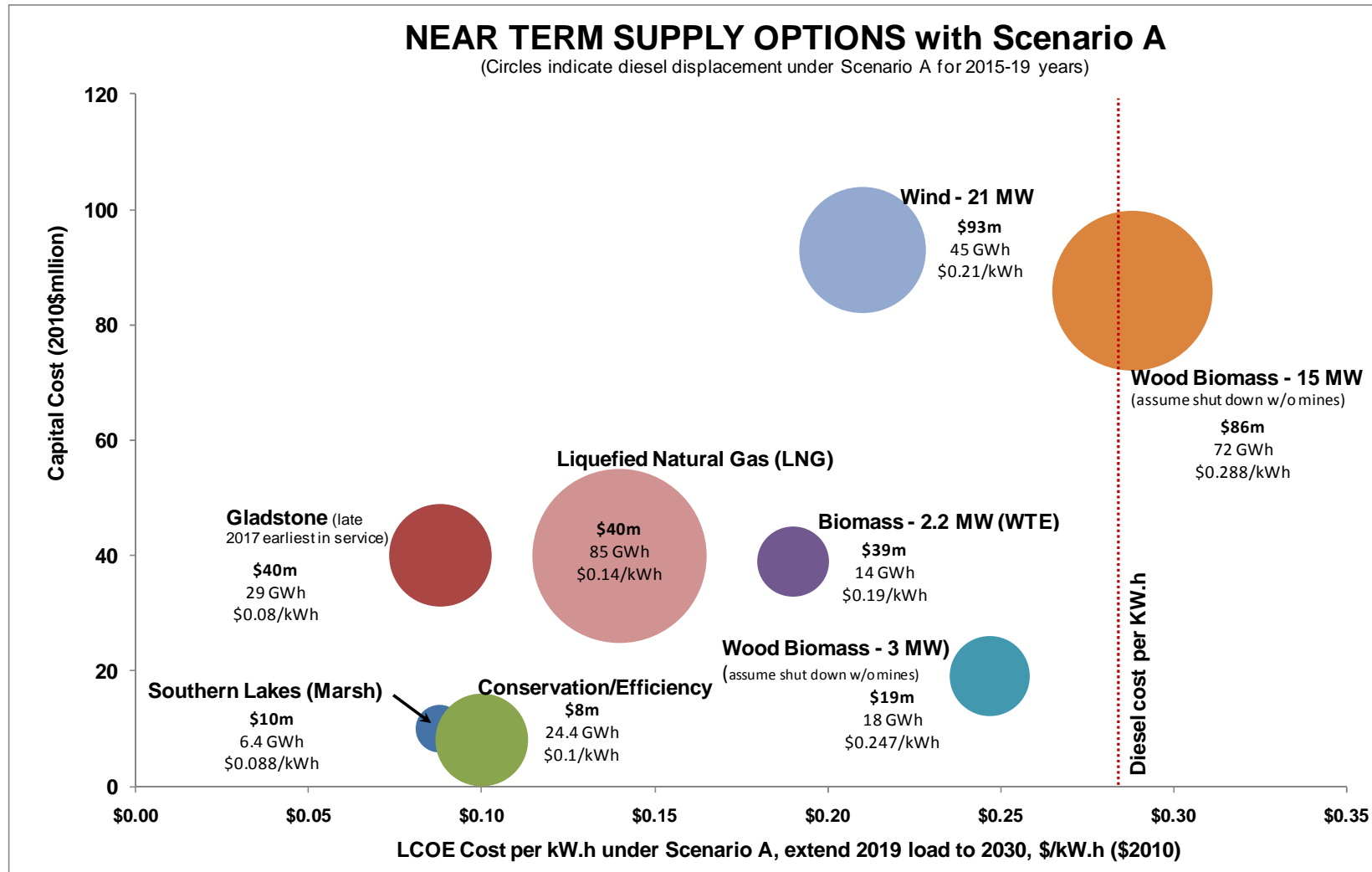
<sup>42</sup> These figures show the maximum potential DSM/SSE (conservation/efficiency) diesel displacement impacts assumed in the 2011 Resource Plan for non-industrial load reduction during the 2015-2019 time period. As noted in Appendix A, pending completion of current DSM/SSE planning, it is considered that likely DSM/SSE over the period to 2030 will be 50% of this maximum. In the near-term period from 2015 to 2019, DSM/SSE will be in an initial implementation phase and accordingly may be less (relative to the 2011 Resource Plan maximums) than levels expected to be achieved by 2030.

Figure 8-2: Overview of Near-Term Resource Options with Scenario A Loads (LCOE, Capital Cost & Diesel Displacement)



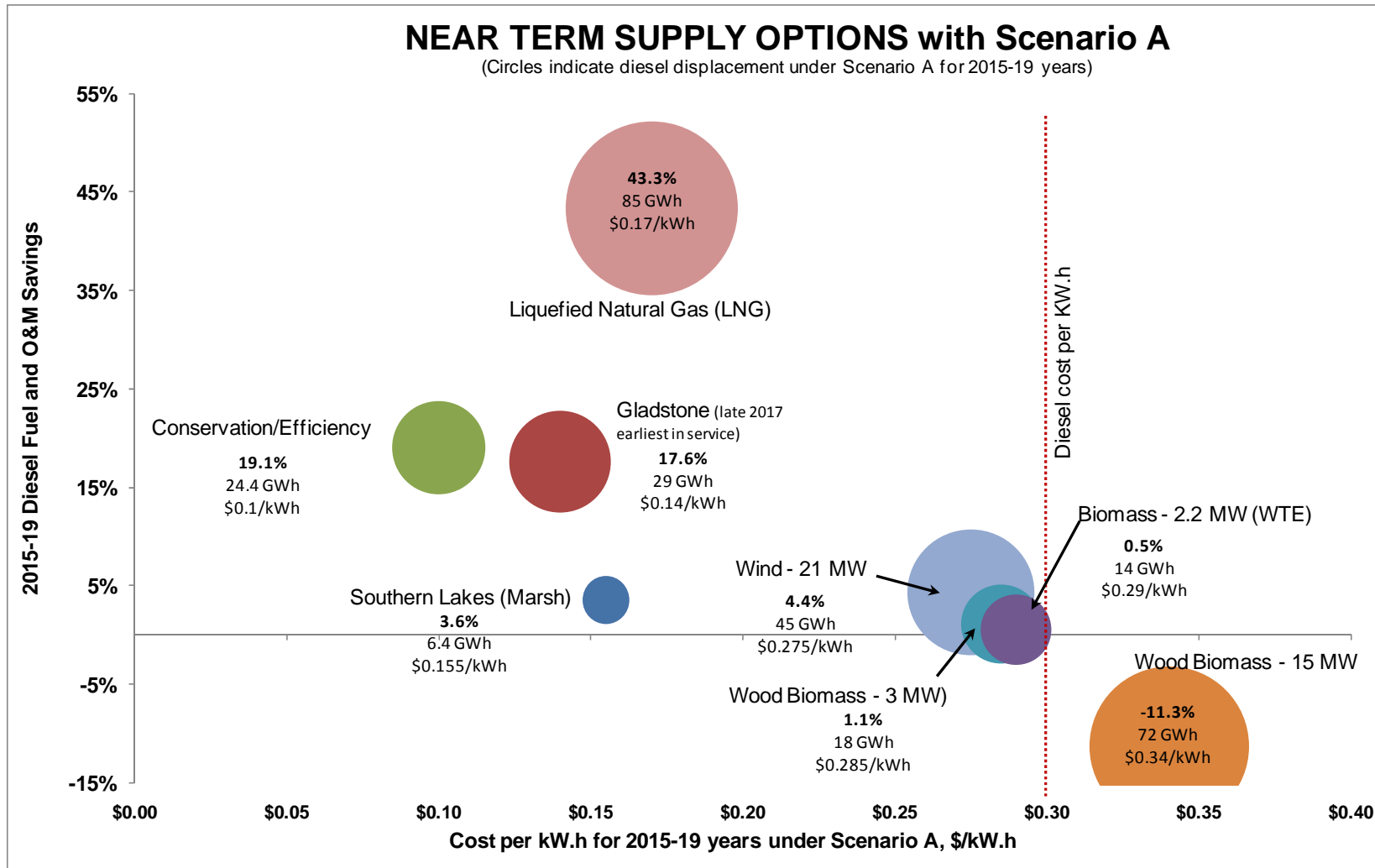
Source: Table 8-2 and Table 8-1.

**Figure 8-3: Overview of Near-Term Resource Options with Scenario A Loads  
 (LCOE with 2019 load extended to 2030, Capital Cost & Diesel Displacement)**



Source: Table 8-2 and Table 8-1.

**Figure 8-4: Overview of Near-Term Resource Options with Scenario A Loads 2015-2019**  
 (Cost per kW.h, Diesel Fuel and O&M Savings, & Diesel Displacement)



Source: Table 8-2 and Table 8-1.

## **Recommended Plans**

Based on the 2011 Resource Plan, Yukon Energy's recommended plans for the period prior to 2015 include the following (in addition to implementing cost-effective DSM/SSE pursuant to the separate ongoing planning process currently underway with other parties):

- 1. LNG Transition Option:** Subject to successful completion of current assessments, determine whether Yukon Energy is able to establish LNG generating capability in Whitehorse prior to 2015 with sufficient capacity to displace grid diesel generation under current Base Case grid load forecasts, and determine the feasibility of utilizing LNG in the event that material additional near-term grid loads occur such as those assessed in Scenarios A and B. This action is being undertaken to implement LNG as a transition option that is able to meet current forecast loads with the least cost option available for near-term implementation, i.e., prior to 2015, and with reduced GHG and other emissions relative to diesel generation.
  
- 2. Near-term Hydro Enhancements:**
  - a. Complete the required environmental, engineering and remediation studies related to the Marsh Lake Storage hydro enhancement project and make a determination whether it is feasible and cost effective to proceed once this information is available.
  
  - b. Plan within the next 6 to 12 months to reach a final determination regarding whether Gladstone Diversion is feasible to pursue further at this time, based on discussions with local First Nations and regulators.
  
- 3. Future Development:**
  - a. **Wind:** Finish current Ferry Hill wind monitoring in order to have this project shelf-ready to pursue through regulatory submissions and other development activity at such time as grid loads and other relevant conditions indicate that this project would be cost-effective to implement. Continue to examine for initial development the feasibility of smaller wind projects in the range of 10 MW to meet suitable grid loads.
  
  - b. **Greenfield Hydro Sites:** Continue to carry out planning studies to identify and plan priority longer-term greenfield hydro development opportunities as recommended in the 2011 Resource Plan, including Hoole and Finlayson sites, and seek funding support for these activities.

**4. Other Longer-Term Resource Planning:**

- a. **Geothermal:** Carry out scaled down geothermal investigations and look for funding support for geothermal exploration and studies, and seek funding support for these activities.
- b. **Grid Extensions:** Continue to explore opportunities to extend the grid within Yukon, and to connect the Yukon grid to British Columbia and/or Alaska (including Skagway). A watching brief with regard to grid extensions to BC or Alaska and other potential longer-term resource options.
- c. **Wood Biomass:** Identify and pursue opportunities for a small scale (e.g., 2 to 3 MW) wood biomass pilot project, potentially in association with existing wood operations at Haines Junction, and seek funding support for this pilot project.
- d. **Other Options:** Continue watching briefs with regard to other resource options, including:
  - i. Solar (cost-effective proven technology development suited to Yukon market conditions); and
  - ii. Pipeline/natural gas (commitments by others regarding Alaska Highway Pipeline and/or potential Eagle Plain or other Yukon natural gas development).

## **APPENDIX A: UPDATED NEAR-TERM GRID LOAD SCENARIOS**

The 2011 Resource Plan grid load scenarios are updated on an ongoing basis. As at spring 2012, four load scenarios are currently applicable for Yukon Energy grid generation and capacity planning (see Table A-1):

1. Load scenarios without connection of major new mines:
  - a. **Base Case:**<sup>43</sup>
    - i. GRA forecast loads for 2012 and 2013;
    - ii. non-industrial growth after 2013 at 2.26%/year less 50% of DSM/SSE assumed in 2011 Resource Plan;
    - iii. Minto generation load at 46.7 GW.h/yr (same as 2013) until 2019, and 23.4 GW.h in 2020 until mid-year (no load thereafter);
    - iv. Alexco generation load at 21.7 GW.h/year 2014-16 (as compared to 15.9 GW.h/yr forecast in 2013); 15.0 GW.h/yr assumed 2017-2020 (no load thereafter); and
    - v. Whitehorse Copper Tailings (WHCT) at 9.3 GW.h/yr 2014-2018 (as compared to 5.2 GW.h/yr in 2013) and 4.1 GW.h in 2019 (no load thereafter).
  - b. **Base Case with Brewery Creek:** Base Case with the added connection, starting January 2014, of Brewery Creek mine with generation load assumed of 20.5 GW.h/yr in 2014 and 33.88 GW.h/yr thereafter until the end of 2023<sup>44</sup>.
2. Load scenarios with connection of major new mines:
  - a. **Scenario A:** Base Case with Brewery Creek and Victoria Gold mine, starting January 1, 2015 with generation load of 103.3 GW.h/yr that continues until the end of 2024 (no load thereafter)<sup>45</sup>.

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<sup>43</sup> The Base Case loads are expected to be reviewed in future to consider higher near-term non-industrial load growth (related to increased use of electric heat, consideration of Whistle Bend subdivision development impacts, and expected DSM/SSE timing which may indicate lower DSM/SSE impacts in near-term), and more recent information on Minto, Alexco and WHCT loads. The current Base Case does not consider Capstone's June 2012 announcement of Phase VI Pre-feasibility study results that extend Minto mine life to 2022. PPA negotiation for WHCT has not yet commenced.

<sup>44</sup> Negotiation of a PPA with Brewery Creek has not yet commenced. The load forecast includes expansion as provided by WHCT plans. This mine has expressed interest in connection in second half of 2013.

<sup>45</sup> PPA negotiations are ongoing with Victoria Gold (an earlier LOI set out principles for connection to the grid). It is assumed that Victoria Gold will pay all costs required for grid connection, plus upgrade of the Mayo-Keno line. The timing for connection of this mine remains uncertain (but will not be earlier than the Q1 2015 assumed in Scenario A).

- b. **Scenario B:** Base Case with Brewery Creek, Victoria Gold and Carmacks Copper mine, starting January 1, 2015 with generation load of 56.5 GW.h/yr that continues until the end of 2020 (no load thereafter)<sup>46</sup>.

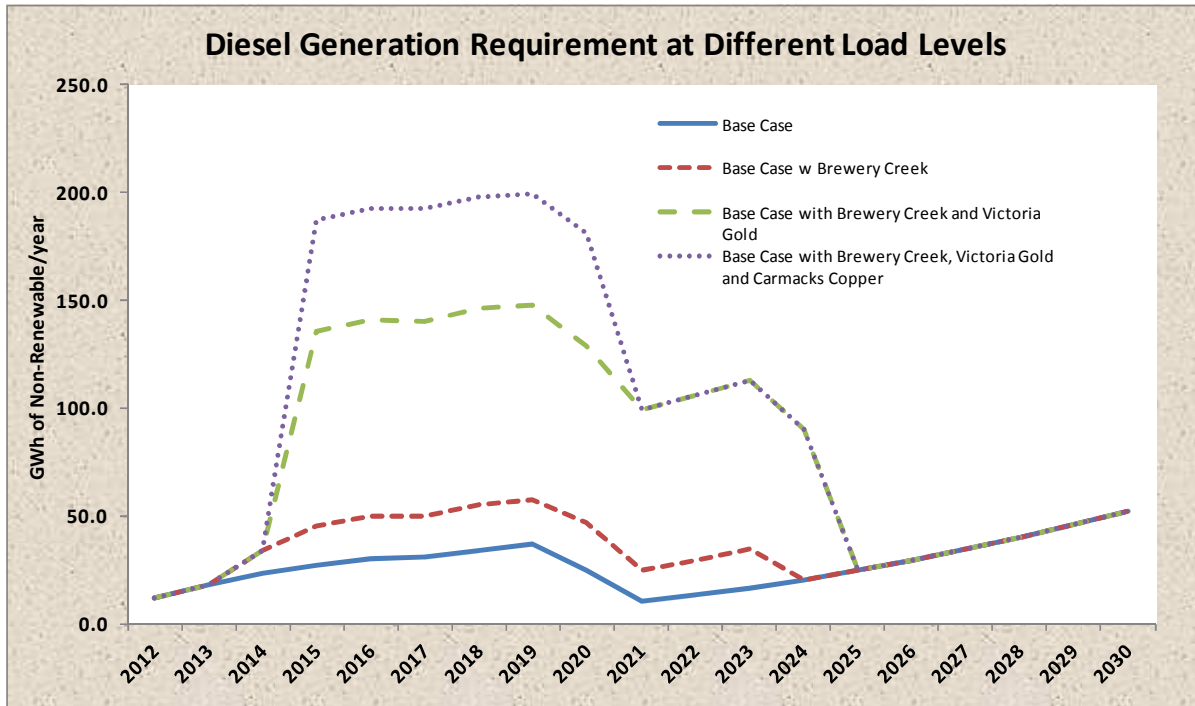
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<sup>46</sup> Carmacks Copper has recently re-started its regulatory review processes, with an announced filing of a revised application planned this fall with YESAB, followed shortly thereafter with revised filing with the YWB. PPA discussions occurred in the past, and have been restarted – 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 during 2015 or (perhaps more likely) during 2016.

Table A-1: Updated Grid Load Scenarios

| Forecast Years | Base Case                  |                        |                         | Base Case w Brewery Creek  |                        |                         | Base Case with Brewery Creek and Victoria Gold |                        |                         | Base Case with Brewery Creek, Victoria Gold and Carmacks Copper |                        |                         |
|----------------|----------------------------|------------------------|-------------------------|----------------------------|------------------------|-------------------------|--|------------------------|-------------------------|---|------------------------|-------------------------|
|                | 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) |
| 2012           | 359.0                      | 56.9                   | 415.9                   | 359.0                      | 56.9                   | 415.9                   | 359.0  | 56.9                   | 415.9                   | 359.0   | 56.9                   | 415.9                   |
| 2013           | 362.6                      | 67.8                   | 430.4                   | 362.6                      | 67.8                   | 430.4                   | 362.6  | 67.8                   | 430.4                   | 362.6   | 67.8                   | 430.4                   |
| 2014           | 365.5                      | 77.8                   | 443.3                   | 365.5                      | 98.4                   | 463.9                   | 365.5  | 98.4                   | 463.9                   | 365.5   | 98.4                   | 463.9                   |
| 2015           | 371.3                      | 77.8                   | 449.1                   | 371.3                      | 111.7                  | 483.0                   | 371.3  | 215.0                  | 586.2                   | 371.3   | 271.5                  | 642.8                   |
| 2016           | 377.2                      | 77.8                   | 455.0                   | 377.2                      | 111.7                  | 488.9                   | 377.2  | 215.0                  | 592.1                   | 377.2   | 271.5                  | 648.7                   |
| 2017           | 383.2                      | 71.1                   | 454.3                   | 383.2                      | 104.9                  | 488.2                   | 383.2  | 208.2                  | 591.4                   | 383.2   | 264.7                  | 648.0                   |
| 2018           | 389.4                      | 71.1                   | 460.5                   | 389.4                      | 104.9                  | 494.4                   | 389.4  | 208.2                  | 597.6                   | 389.4   | 264.7                  | 654.1                   |
| 2019           | 395.7                      | 65.9                   | 461.6                   | 395.7                      | 99.8                   | 495.5                   | 395.7  | 203.0                  | 598.8                   | 395.7   | 259.6                  | 655.3                   |
| 2020           | 402.2                      | 38.4                   | 440.5                   | 402.2                      | 72.3                   | 474.4                   | 402.2  | 175.5                  | 577.7                   | 402.2   | 232.0                  | 634.2                   |
| 2021           | 408.8                      |                        | 408.8                   | 408.8                      | 33.9                   | 442.7                   | 408.8  | 137.1                  | 545.9                   | 408.8   | 137.1                  | 545.9                   |
| 2022           | 415.5                      |                        | 415.5                   | 415.5                      | 33.9                   | 449.4                   | 415.5  | 137.1                  | 552.7                   | 415.5   | 137.1                  | 552.7                   |
| 2023           | 422.4                      |                        | 422.4                   | 422.4                      | 33.9                   | 456.3                   | 422.4  | 137.1                  | 559.6                   | 422.4   | 137.1                  | 559.6                   |
| 2024           | 429.5                      |                        | 429.5                   | 429.5                      |                        | 429.5                   | 429.5  | 103.3                  | 532.8                   | 429.5   | 103.3                  | 532.8                   |
| 2025           | 436.7                      |                        | 436.7                   | 436.7                      |                        | 436.7                   | 436.7  |                        | 436.7                   | 436.7   |                        | 436.7                   |
| 2026           | 444.1                      |                        | 444.1                   | 444.1                      |                        | 444.1                   | 444.1  |                        | 444.1                   | 444.1   |                        | 444.1                   |
| 2027           | 451.7                      |                        | 451.7                   | 451.7                      |                        | 451.7                   | 451.7  |                        | 451.7                   | 451.7   |                        | 451.7                   |
| 2028           | 459.4                      |                        | 459.4                   | 459.4                      |                        | 459.4                   | 459.4  |                        | 459.4                   | 459.4   |                        | 459.4                   |
| 2029           | 467.3                      |                        | 467.3                   | 467.3                      |                        | 467.3                   | 467.3  |                        | 467.3                   | 467.3   |                        | 467.3                   |
| 2030           | 475.3                      |                        | 475.3                   | 475.3                      |                        | 475.3                   | 475.3  |                        | 475.3                   | 475.3   |                        | 475.3                   |

Figure A-1: Diesel Generation Requirements at Different Forecast Loads: 2012-2030



| <u>Diesel Energy Requirement (GWh)</u>                                 | <u>2012</u> | <u>2015</u> | <u>2020</u> | <u>2025</u> | <u>2030</u> |
|--|-------------|-------------|-------------|-------------|-------------|
| <b>Base Case</b>   | 11.5        | 27.0        | 24.4        | 24.5        | 51.9        |
| <b>Base Case with Brewery Creek</b>                                    | 11.5        | 45.5        | 47.1        | 24.5        | 51.9        |
| <b>Base Case with Brewery Creek and Victoria Gold</b>                  | 11.5        | 135.2       | 128.8       | 24.5        | 51.9        |
| <b>Base Case with Brewery Creek, Victoria Gold and Carmacks Copper</b> | 11.5        | 187.1       | 181.0       | 24.5        | 51.9        |

Figure A-1 and table provide the forecast diesel generation requirement during the 20-year planning period for each of the load scenarios.

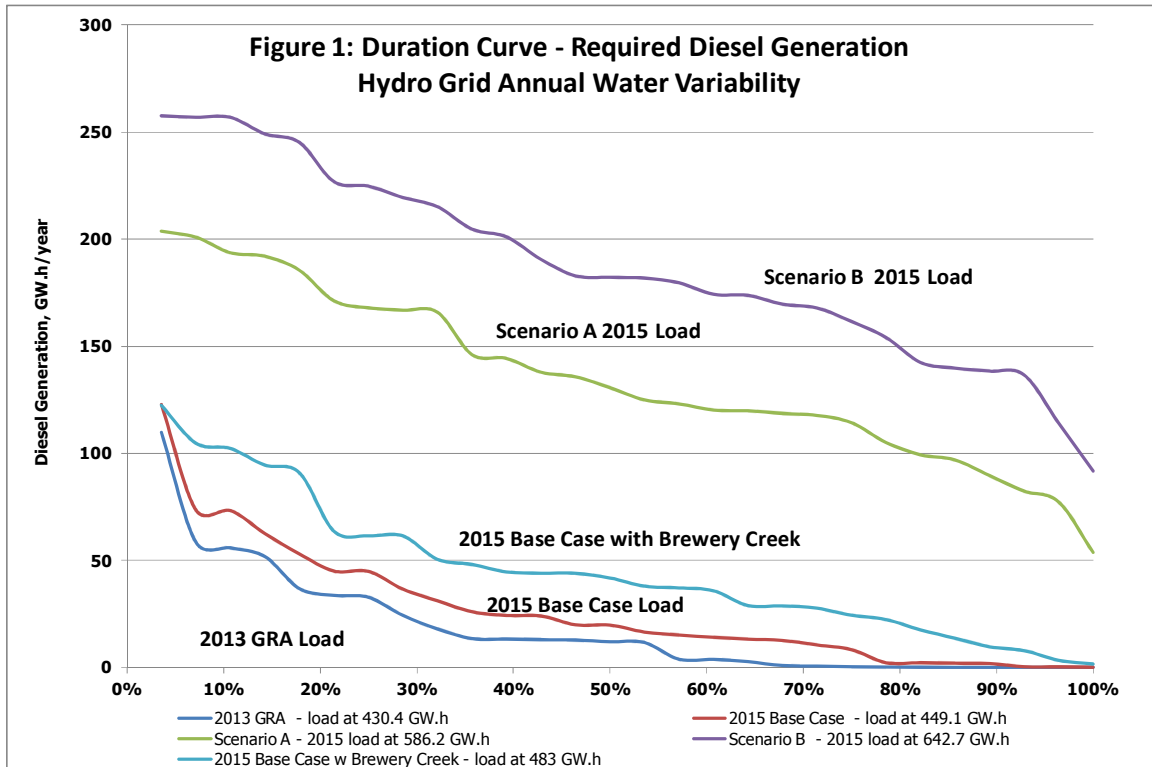
1. The numbers are based on updated load for 2012-2030.
2. Diesel requirement numbers are long-term average diesel.
3. Model run with Aishihik 10-year rolling average rule, Mayo Lake assumed in-service by winter 2013/14 (more recent information suggests earliest in-service is now winter 2014/15).

Diesel generation forecasts for each load scenario reflect long-term average hydro generation, i.e., the average hydro generation over 28 recorded water year conditions at the assumed load, as estimated by the power benefits model used by YEC for grid generation planning. Table A-2 and the Figure A-2 below it provide a detailed review of potential diesel generation variability for the year 2015 under each load scenario for each of the 28 water years (the figure shows the annual load duration curve for diesel for each load scenario).

**Table A-2: Forecast Diesel Generation Variability (GW.h) Depending on Water Year Conditions - Load Scenarios for 2015 and 28 Water Years of Record**

| Water Year | Average Annual Diesel Generation (Averaged Load Years for 28 Water Years) |                                     |   |                                      |                                      | Distribution of Annual Water Year Loads (Figure 1) |                               |                                     |   |                                      |                                      |       |
|------------|---|-------------------------------------|---|--------------------------------------|--------------------------------------|--|-------------------------------|-------------------------------------|---|--------------------------------------|--------------------------------------|-------|
|            | 2013 GRA - load at 430.4 GW.h   | 2015 Base Case - load at 449.1 GW.h | 2015 Base Case w Brewery Creek - load at 483 GW.h | Scenario A - 2015 load at 586.2 GW.h | Scenario B - 2015 load at 642.7 GW.h | % of Years not less than                           | 2013 GRA - load at 430.4 GW.h | 2015 Base Case - load at 449.1 GW.h | 2015 Base Case w Brewery Creek - load at 483 GW.h | Scenario A - 2015 load at 586.2 GW.h | Scenario B - 2015 load at 642.7 GW.h |       |
| 1981       | 0.6   | 2.2                                 | 9.8   | 114.3                                | 182.2                                | 1  | 4%                            | 109.9                               | 122.7   | 122.4                                | 203.7                                | 257.4 |
| 1982       | 2.6   | 10.5                                | 48.2  | 135.7                                | 181.8                                | 2  | 7%                            | 58.5                                | 73.5  | 104.8                                | 201.0                                | 256.8 |
| 1983       | 3.8   | 8.3                                 | 38.1  | 118.6                                | 173.8                                | 3  | 11%                           | 55.9                                | 73.2  | 102.3                                | 193.7                                | 256.7 |
| 1984       | 11.6  | 19.9                                | 63.7  | 168.0                                | 226.8                                | 4  | 14%                           | 51.8                                | 62.5  | 94.5                                 | 192.0                                | 249.0 |
| 1985       | 3.7   | 24.2                                | 44.7  | 146.1                                | 201.0                                | 5  | 18%                           | 36.8                                | 52.9  | 90.9                                 | 185.5                                | 245.0 |
| 1986       | 0.9   | 16.5                                | 44.1  | 125.0                                | 169.6                                | 6  | 21%                           | 33.6                                | 45.0  | 63.7                                 | 171.3                                | 226.8 |
| 1987       | 0.1   | 12.6                                | 24.5  | 117.7                                | 179.6                                | 7  | 25%                           | 32.8                                | 44.8  | 61.5                                 | 168.0                                | 224.7 |
| 1988       | 0.0   | 14.1                                | 27.8  | 105.1                                | 142.5                                | 8  | 29%                           | 24.3                                | 36.5  | 61.5                                 | 166.9                                | 219.4 |
| 1989       | 0.0   | 2.2                                 | 8.0   | 89.6                                 | 154.1                                | 9  | 32%                           | 18.0                                | 31.1  | 50.6                                 | 165.9                                | 215.1 |
| 1990       | 0.1   | 1.8                                 | 17.7  | 123.1                                | 174.3                                | 10   | 36%                           | 13.5                                | 26.0  | 48.2                                 | 146.1                                | 204.7 |
| 1991       | 0.0   | 1.9                                 | 13.8  | 96.9                                 | 138.5                                | 11   | 39%                           | 13.3                                | 24.2  | 44.7                                 | 144.3                                | 201.0 |
| 1992       | 0.0   | 0.3                                 | 1.8   | 53.8                                 | 91.9                                 | 12   | 43%                           | 12.9                                | 24.0  | 44.1                                 | 137.9                                | 190.5 |
| 1993       | 0.3   | 0.1                                 | 3.5   | 82.4                                 | 136.7                                | 13   | 46%                           | 12.8                                | 19.9  | 44.1                                 | 135.7                                | 182.9 |
| 1994       | 0.0   | 0.3                                 | 22.5  | 185.5                                | 249.0                                | 14   | 50%                           | 12.0                                | 19.7  | 41.9                                 | 130.7                                | 182.2 |
| 1995       | 12.9  | 31.1                                | 94.5  | 201.0                                | 257.4                                | 15   | 54%                           | 11.6                                | 16.5  | 38.1                                 | 125.0                                | 181.8 |
| 1996       | 51.8  | 62.5                                | 104.8   | 203.7                                | 256.7                                | 16   | 57%                           | 3.8                                 | 15.1  | 37.3                                 | 123.1                                | 179.6 |
| 1997       | 58.5  | 73.5                                | 102.3   | 171.3                                | 215.1                                | 17   | 61%                           | 3.7                                 | 14.1  | 35.9                                 | 120.2                                | 174.3 |
| 1998       | 36.8  | 44.8                                | 90.9  | 193.7                                | 256.8                                | 18   | 64%                           | 2.6                                 | 13.2  | 29.1                                 | 119.8                                | 173.8 |
| 1999       | 109.9   | 122.7                               | 122.4   | 192.0                                | 245.0                                | 19   | 68%                           | 0.9                                 | 12.6  | 28.9                                 | 118.6                                | 169.6 |
| 2000       | 55.9  | 73.2                                | 61.5  | 130.7                                | 167.9                                | 20   | 71%                           | 0.6                                 | 10.5  | 27.8                                 | 117.7                                | 167.9 |
| 2001       | 32.8  | 45.0                                | 28.9  | 77.4                                 | 114.3                                | 21   | 75%                           | 0.3                                 | 8.3   | 24.5                                 | 114.3                                | 161.6 |
| 2002       | 24.3  | 36.5                                | 35.9  | 120.2                                | 182.9                                | 22   | 79%                           | 0.1                                 | 2.2   | 22.5                                 | 105.1                                | 154.1 |
| 2003       | 13.3  | 26.0                                | 50.6  | 166.9                                | 224.7                                | 23   | 82%                           | 0.1                                 | 2.2   | 17.7                                 | 99.3                                 | 142.5 |
| 2004       | 33.6  | 52.9                                | 61.5  | 165.9                                | 219.4                                | 24   | 86%                           | 0.0                                 | 1.9   | 13.8                                 | 96.9                                 | 139.9 |
| 2005       | 18.0  | 19.7                                | 44.1  | 137.9                                | 190.5                                | 25   | 89%                           | 0.0                                 | 1.8   | 9.8                                  | 89.6                                 | 138.5 |
| 2006       | 12.8  | 15.1                                | 37.3  | 144.3                                | 204.7                                | 26   | 93%                           | 0.0                                 | 0.3   | 8.0                                  | 82.4                                 | 136.7 |
| 2007       | 12.0  | 24.0                                | 41.9  | 119.8                                | 161.6                                | 27   | 96%                           | 0.0                                 | 0.3   | 3.5                                  | 77.4                                 | 114.3 |
| 2008       | 13.5  | 13.2                                | 29.1  | 99.3                                 | 139.9                                | 28   | 100%                          | 0.0                                 | 0.1   | 1.8                                  | 53.8                                 | 91.9  |
| Average    | 18.2  | 27.0                                | 45.5  | 135.2                                | 187.1                                |  |                               | 18.2                                | 27.0  | 45.5                                 | 135.2                                | 187.1 |

**Figure A-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 A-3, assuming existing plant and planned diesel unit retirements and applying YEC's approved N-1 and LOLE capacity planning criteria. These shortfalls assume that L172 is re-enforced (with by twinning or by provision for the 35 kV system to be able to by-pass this line between Takhini and McIntyre substations).

The following are noted regarding assumed diesel unit retirements, using projected shortfalls under the Base Case to demonstrate the impact of assumed retirements:

- 2015 Base Case shortfall of 3.3 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).
  - Replacing one of these units with at least the same capacity would totally resolve the 2015 shortfall.
- 2020 Base Case shortfall of 15.7 MW: reflects following 13.11 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 1 unit (0.85 MW in 2019).
- 2025 Base Case shortfall of 38.1 MW: reflects following 28.61 MW of diesel unit retirements:
  - The above 13.11 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 51.5 MW: reflects following 34.41 MW of diesel unit retirements:
  - The above 28.61 MW retired by 2025 plus.
  - Whitehorse CAT (3.0 MW in 2026).
  - Faro CAT (2.8 MW in 2027).

**Table A-3: Grid Capacity Planning - Forecast MW Surplus (Shortfall) by Load Scenario: 2012-2030**

Comparison of Peak, N-1 and LOLE requirements

| Forecast Years | Base Case |                              |                               | Base Case w Brewery Creek |                              |                               | Base Case with Brewery Creek and Victoria Gold |                              |                               | Base Case with Brewery Creek, Victoria Gold and Carmacks Copper |                              |                               |
|----------------|-----------|------------------------------|-------------------------------|---------------------------|------------------------------|-------------------------------|--|------------------------------|-------------------------------|---|------------------------------|-------------------------------|
|                | 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) |
| 2012           | 80.1      | 7.2                          | 7.2                           | 80.1                      | 7.2                          | 7.2                           | 80.1   | 7.2                          | 7.2                           | 80.1  | 7.2                          | 7.2                           |
| 2013           | 81.1      | 6.5                          | 6.5                           | 81.1                      | 6.5                          | 6.5                           | 81.1   | 6.5                          | 6.5                           | 81.1  | 6.5                          | 6.5                           |
| 2014           | 82.6      | 2.4                          | 2.4                           | 83.8                      | 2.4                          | 2.4                           | 83.8   | 2.4                          | 2.4                           | 83.8  | 2.4                          | 2.4                           |
| 2015           | 83.7      | -3.3                         | -3.3                          | 86.9                      | -3.3                         | -3.5                          | 99.9   | -3.3                         | -16.5                         | 107.9   | -3.3                         | -24.5                         |
| 2016           | 84.9      | -4.4                         | -4.4                          | 88.1                      | -4.4                         | -4.6                          | 101.1  | -4.4                         | -17.6                         | 109.1   | -4.4                         | -25.6                         |
| 2017           | 85.2      | -6.5                         | -6.5                          | 88.4                      | -6.5                         | -6.5                          | 101.4  | -6.5                         | -18.8                         | 109.4   | -6.5                         | -26.8                         |
| 2018           | 86.4      | -8.5                         | -8.5                          | 89.6                      | -8.5                         | -8.5                          | 102.6  | -8.5                         | -20.8                         | 110.6   | -8.5                         | -28.8                         |
| 2019           | 87.7      | -12.3                        | -12.3                         | 90.9                      | -12.3                        | -12.3                         | 103.9  | -12.3                        | -24.6                         | 111.9   | -12.3                        | -32.6                         |
| 2020           | 89.0      | -15.7                        | -15.7                         | 92.2                      | -15.7                        | -15.7                         | 105.2  | -15.7                        | -28.0                         | 113.2   | -15.7                        | -36.0                         |
| 2021           | 81.2      | -25.5                        | -25.5                         | 84.4                      | -25.5                        | -25.5                         | 97.4   | -25.5                        | -28.7                         | 97.4  | -25.5                        | -28.7                         |
| 2022           | 82.5      | -26.8                        | -26.8                         | 85.7                      | -26.8                        | -26.8                         | 98.7   | -26.8                        | -30.0                         | 98.7  | -26.8                        | -30.0                         |
| 2023           | 83.9      | -28.2                        | -28.2                         | 87.1                      | -28.2                        | -28.2                         | 100.1  | -28.2                        | -31.4                         | 100.1   | -28.2                        | -31.4                         |
| 2024           | 85.3      | -29.6                        | -29.6                         | 85.3                      | -29.6                        | -29.6                         | 98.3   | -29.6                        | -29.6                         | 98.3  | -29.6                        | -29.6                         |
| 2025           | 86.7      | -38.1                        | -38.1                         | 86.7                      | -38.1                        | -38.1                         | 86.7   | -38.1                        | -38.1                         | 86.7  | -38.1                        | -38.1                         |
| 2026           | 88.2      | -42.5                        | -42.5                         | 88.2                      | -42.5                        | -42.5                         | 88.2   | -42.5                        | -42.5                         | 88.2  | -42.5                        | -42.5                         |
| 2027           | 89.7      | -46.8                        | -46.8                         | 89.7                      | -46.8                        | -46.8                         | 89.7   | -46.8                        | -46.8                         | 89.7  | -46.8                        | -46.8                         |
| 2028           | 91.2      | -48.4                        | -48.4                         | 91.2                      | -48.4                        | -48.4                         | 91.2   | -48.4                        | -48.4                         | 91.2  | -48.4                        | -48.4                         |
| 2029           | 92.8      | -49.9                        | -49.9                         | 92.8                      | -49.9                        | -49.9                         | 92.8   | -49.9                        | -49.9                         | 92.8  | -49.9                        | -49.9                         |
| 2030           | 94.4      | -51.5                        | -51.5                         | 94.4                      | -51.5                        | -51.5                         | 94.4   | -51.5                        | -51.5                         | 94.4  | -51.5                        | -51.5                         |