YUKON ENERGY 20-YEAR RESOURCE PLAN: 2011-2030

DECEMBER 2011

OUTLINE OF RESOURCE PLAN REPORT & SUPPORTING DOCUMENTS

Yukon Energy's 2011 Resource Plan ("2011 Resource Plan" or "Plan") addresses updated generation and transmission priorities in Yukon for the 20-year planning period, from 2011 to 2030. It focuses on resource planning options for the next five years (2011-2015) to meet supply requirements out to 2017 and to protect the ability to proceed with longer-term legacy development options with potential construction start in 2021 or thereafter.

The Plan is divided into seven sections: Resource Planning Principles (Section 1), Forecast Load Requirements (Section 2), Resource Planning Options (Section 3), Default Diesel Portfolio (Section 4), Minimum Greenhouse Gas Emissions Portfolio Options (Section 5), LNG Transition Portfolio Options (Section 6) and Resource Plan Summary and Conclusions (Section 7).

This Plan updates for the 2006-2025 planning period, Yukon Energy's previous 20-Year Resource Plan that was submitted to the Yukon Utilities Board for public review in mid-2006. It provides overall planning guidance for the next five years, and (as with the 2006 Resource Plan) remains subject to ongoing adjustment as new information and priorities emerge. The following are specifically noted in this regard:

- The updated load forecasts used to prepare the 2011 Resource Plan were mainly developed in the first quarter of 2011, and reflect information available at that time.
- Information on specific supply options reflect technical papers presented at Yukon Energy's March 2011 Charrette as well as information available from ongoing Yukon Energy resource planning studies.
- The 2011 Resource Plan has been prepared before a detailed energy conservation potential review now being carried out by Yukon Energy, Yukon Electrical and the Yukon Government is completed. This review will determine what Demand Side Management (DSM) programs are feasible along with an estimate of the cost implications if those programs were implemented[1].

Yukon Energy is committed to continue engaging Yukoners in resource planning, including by providing stakeholders the opportunity to comment on the draft 2011 Resource Plan before it is finalized.

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[1] It is assumed in the 2011 Resource Plan that DSM programs will be implemented concurrent with any other resource supply options. A range of potential DSM program impacts is provided when each resource supply option is assessed.

PREFACE – POLICY & PUBLIC ENGAGEMENT CONTEXT

Yukon Energy is the primary generator and transmitter of electrical energy in the Yukon. Established in 1987, Yukon Energy operates as a regulated utility at arm's length from the Yukon government. Its mandate is to plan, generate, transmit and distribute a continuing and adequate supply of cost-effective, sustainable and reliable electricity for customers in the Yukon.

BACKGROUND

The 2011 Resource Plan reflects a continuation of a long standing corporate policy of economically developing sustainable local resources to reduce and avoid, where possible, the need to generate power with diesel. Further, given current realities added attention is directed at securing options that can assist in reducing the high greenhouse gas (GHG) emissions[2] associated with diesel generation no matter where it occurs in Yukon.

- **In Yukon, traditional energy policy objectives have focused on development, where economically feasible, of local resources instead of importing diesel fuel** - Prior to Yukon Energy's acquisition of the Northern Canada Power Commission (NCPC) assets in Yukon, NCPC utilized major industrial mine developments at Keno and Faro to develop hydro and transmission assets to displace imported diesel fuel. Subsequently, Yukon Energy (with the help of its parent Yukon Development Corporation (YDC)) has studied and assessed various supply options which can be used to avoid the use of diesel generation including enhancing existing infrastructure, potential wind , new hydro and geothermal supply options. Specifically within the last decade, Yukon Energy has enhanced existing assets by developing the Mayo-Dawson and Carmacks-Stewart transmission lines and by enhancing both the Mayo and Aishihik hydro facilities. Yukon resource planning, however, must still reflect the lack of connection to an external grid - a factor that prevents external sale of surplus renewable generation as well as import of external market-priced energy supplies.
- **Reliability of electricity supply remains a fundamental requirement for resource planning** - Notwithstanding the ongoing objective to displace imported diesel fuel required to meet ongoing energy requirements, reliance on diesel generation has continued to play a major

[2] GHG emissions refer to gas emissions that absorb and emit radiation at specific wavelengths within the spectrum of infrared radiation emitted by the Earth's surface, the atmosphere and clouds (see Environment Canada web site - climate change).The 2011 Resource Plan estimates of GHG emissions from various resource options primarily reflect available estimates of combined carbon dioxide, methane and nitrous oxide emissions.

part in resource planning for reliability and peaking. Capacity reliability planning for the grids must provide sufficient reserve capacity not to exceed a Loss of Load Expectation of 2 hours/year and to protect customers against the largest single contingency (N-1), which for the Whitehorse Aishihik Faro (WAF) grid is loss of the Aishihik-Whitehorse transmission line[3].

- **New realities and new resource supply development opportunities** - The hydro surplus in existence in 2006 is no longer available, reflecting faster than expected non-industrial growth combined with new grid-connected industrial loads. Further, most of the hydro enhancement opportunities identified in the 2006 Resource Plan (or subsequent studies in 2007/08) have now been either developed or are currently under active consideration. As a result, in order to displace future diesel energy generation, consideration is now required for new resource supply options that will minimize near-term reliance on diesel and transition toward longer-term development of preferred new renewable generation resources.

- **Over the past several years Yukon Government has pursued economic development policies that support development of the mining sector[4]** - Support for mining development in Yukon has been ongoing with exploration activity increasing from $8 million in 2002 to over $80 million in 2006[5]. In 2010, a record 83,863 claims were staked and over $150 million was spent in mineral exploration[6]. In 2011, mineral exploration expenditures are expected to exceed $250 million[7], a record high[8]. Rapid mining development creates a wide range of related development activities throughout Yukon, including the potential for major increases in Yukon electricity generation within the next 10 to 20 years. In the same way that Yukon's current

[3] These concepts are explained in detail in Section 2.3 and Appendix D.

[4] The former premier noted at the 2011 Round Up, "Yukon's economy is one of the best in Canada, and the minerals industry is a cornerstone of that growth," Fentie said. "We are seeing the industry create many opportunities and benefits for Yukon residents, businesses and communities." "Yukon is one of the top jurisdictions in the world for mining and exploration and we are optimistic about the growth potential for this very important industry". See also http://www.gov.yk.ca/news/11-013.html.

[5] Press releases from 2007 note YG intention to focus on assisting the advanced exploration projects become operating mines. See http://www.gov.yk.ca/news/2007/07-014.html.

[6] Energy Mines and Resources Minister Patrick Rouble noted at the 2011 Round up that Yukon had experienced "a banner year with new mines commencing operation and unprecedented levels of exploration," and "In addition to celebrating our success, we are working to ensure long-term industry growth that will continue to provide important jobs and business opportunities for Yukoners." See http://www.gov.yk.ca/news/11-013.html.

[7] YG Economic Development – Yukon Economic Outlook 2011. See (http://economics.gov.yk.ca/Files/Economic%20Outlook/Outlook2011.pdf).

[8] Recent initiatives to support and foster mining development in Yukon include 2008 amendments to the Quartz Mining Act and Miners Lien Act to provide clarity and certainty for mine development in Yukon. Yukon's then Minister of Energy, Mines and Resources noted, "Yukon's mining sector is a significant contributor to Yukon's economy" and "the Yukon government is committed to encouraging and supporting a sustainable mineral industrial while ensuring that Yukoners receive maximum benefits from our resources". In this regard the Quartz Mining Act was amended to lower exploration costs (while also ensuring royalty rates for mine development are competitive with other Canadian mining jurisdictions. See http://www.gov.yk.ca/news/2008/08-299.html.

renewable hydro generation and grid infrastructure reflects the impact of past major mine developments, future electricity supply development in response to new mine developments could shape Yukon electricity infrastructure for decades to come.

POLICY OBJECTIVES & REALITIES GUIDING RESOURCE PLANNING IN YUKON

When considering potential supply options, most jurisdictions in Canada are guided by a set of broad policy objectives set by governments and regulators. The 2006 Resource Plan reflects all relevant government policies including those by way of directions provided under the *Public Utilities Act* or other relevant legislation that comprise the regulatory context in which Yukon Energy operated at that time.

In addition to the above, Yukon Energy is preparing its 2011 Resource Plan within a new industry and government policy environment that was not present in 2006. This, coupled with a new corporate approach to stakeholder engagement, has created a complex planning environment in which future energy projects and planning processes are assessed.

GOVERNMENT OF YUKON ENERGY POLICY AND CLIMATE CHANGE ACTION PLAN

The 2011 Resource Plan is influenced by the *Energy Strategy for Yukon* (2009) and the *Yukon Climate Change Action Plan* (2009). These policies were developed after extensive public consultation and are intended to work together to "address the reduction of greenhouse gas emissions" (Energy Strategy for Yukon, page 14).

The most recent Shareholder's Letter of Expectation from the Government of Yukon to the Yukon Development Corporation (YDC) and Yukon Energy Corporation provides Yukon Energy and its parent corporation (YDC) with direction to work with the Yukon government and other stakeholders on the implementation of the *Energy Strategy for Yukon* and the *Climate Change Action Plan*[9].

(i) YG Energy Strategy

The Energy Strategy for Yukon focuses on four priorities[10]:

- Conserving energy and using it more efficiently;
- Increasing the supply of energy and using it more efficiently;

[9] Full text of this letter can be found in Appendix B.
[10] Ibid. Pg 2.

- Meeting Yukon's current and future electricity needs; and
- Managing responsible oil and gas development in Yukon.

Within these priorities, a number of strategies and related actions for energy conservation and the development of renewable energy resources are identified. There is also a specific focus on electricity and future energy choices, and Yukon Energy Corporation role in the implementation of electricity-related initiatives.

Energy efficiency and conservation is recognized as the starting point for the Energy Strategy[11] both broadly and as it relates to electricity. The Government of Yukon has committed to increasing energy efficiency in the Yukon by 20% by the year 2020[12]. The Energy Strategy also identifies as a priority increasing the renewable energy supply by 20% by the year 2020 to reduce fossil fuel use and related greenhouse gas emissions[13].

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[11] Ibid. pg. 6.
[12]This objective will be met by reducing the energy consumption in buildings and the transportation sector, promoting the use of energy efficient products and improving the energy efficiency for Yukon government buildings and operations (Energy Strategy pg. 7).
[13] Ibid, pg 11.

The following chart summarizes the Energy Strategy commitments of most relevance to Yukon Energy's 2011 Resource Plan.

Goal	Strategies
Energy efficiency and conservation will be a priority to reduce energy consumption, energy costs and emissions.	• Developing policies that will support energy efficiency and conservation. • Delivering programs to support and demonstrate energy efficiency initiatives that have the potential to reduce greenhouse base emissions and save Yukoners money. • Incorporating long-term energy costs and environmental benefits in capital investment decisions. • Working with other jurisdictions on enhancing the Model Energy Codes for Buildings and for Houses, as well as adding an energy efficiency objective to the National Building Code. • Encouraging the planning and development of energy efficient communities. • Partnering with First Nations and municipalities to improve energy efficiency and conservation in Yukon Communities.
Energy production from renewable sources will be increased to reduce fossil fuel use and greenhouse gas emissions.	• Replacing fossil fuels with cleaner, renewable energy sources where possible. • Demonstrating leadership in developing renewable energy infrastructure. • Investing in research and development of renewable energy technology. • Identifying strategic opportunities to develop new renewable energy sources. • Developing a wood based bio-energy industry in Yukon by building a local market for wood energy technologies and wood fuel products. • Encouraging cost-effective, small-scale renewable energy production to foster innovation and diversify Yukon's supply of electricity resources. • Building partnerships with others to leverage funding and share expertise for renewable energy.
Electricity supply will be increased and demand will be managed to meet current and future electricity needs.	• Enhancing the supply of electricity and managing demand to ensure access to a secure, reliable and cost competitive source of electricity. • Maximizing the use and efficiency of existing hydroelectric infrastructure. • Increasing and diversifying Yukon's supply of electricity from renewable sources to decrease diesel use and minimize greenhouse gas and air emissions. • Considering renewable energy and cleaner sources such as natural gas for all new electricity generation projects. • Leveraging territorial, federal and private funds in infrastructure investments to meet growing electricity demand and promote economic development. • Informing the public about the true costs of electricity and promoting

Goal	Strategies
	incentives and initiatives to encourage energy efficiency and conservation. • Managing electricity demand to reduce energy requirements at peak times. • Working with Yukon Development Corporation, Yukon Energy Corporation and Yukon Electrical Company Limited to develop an improved approach to managing electricity generation and distribution, with the objectives of improving reliability, providing downward pressure on rates, and expanding the system to meet the needs of a growing Yukon economy.
Oil and Gas resources will be developed responsibly for local use within Yukon and export.	• Developing an oil and gas sector in a way that will deliver the greatest benefits to Yukon. • Promoting efficiency and conservation for the use of oil and gas resources. • Reducing Yukon's reliance on imported fossil fuels.
The Energy Strategy for Yukon will set long-term direction and define short term priorities for the Yukon government.	• Evaluating potential energy sources to make choices that will provide the greatest benefits for the least costs. • Setting policy direction for energy development, conservation and use. • Incorporating the Strategy's principles on decision making. • Building partnerships to develop and manage Yukon's energy resources. • Allocating sufficient resources to implement the Strategy. • Coordinating implementation with the Climate Change Action Plan wherever possible. • Reviewing the Strategy to ensure it remains relevant and current. • Demonstrating progress on priority actions.

(ii) YG Climate Action Plan

The *Climate Change Action Plan* builds on the four goals outlined in the *Climate Change Strategy* and reflects the Yukon government's belief that "climate change is happening, that human behaviour is a major contributor, and that a coordinated response is needed[14]" recognizing that the Yukon is a small jurisdiction and it is important to focus on priority actions that provide the most benefit to the Yukon.

[14] Government of Yukon (2010). Climate Change Action Plan. pg. 6.

The following chart summarizes the *Climate Change Action Plan* commitments of most relevance to Yukon Energy's 2011 Resource Plan.

Goal	Strategies
Enhance Knowledge and understanding of climate change.	• Establish a Yukon Research Centre of Excellence. • Establish climate change research study areas. • Develop climate scenarios.
Adapt to climate change.	• Complete a Yukon infrastructure risk and vulnerability assessment and determine adaptation strategies in response. • Develop an inventory of permafrost information for use in decision making. • Complete a Yukon water resources risk and vulnerability assessment. • Create a tool to facilitate the connection and distribution of water quantity and quality data. • Conduct a Yukon forest health risk assessment. • Conduct treatments to reduce forest fuel load and protect communities. • Conduct a Yukon forest tree species and vulnerability assessment.
Reduce greenhouse gas (GHG) emissions.	• Yukon government's internal operations: cap GHG emissions in 2010, reduce GHG emission by 20% by 2015 and become carbon neutral by 2020. • Report to Yukon government operations through 'The Climate Registry'. • Develop a carbon offset policy for internal operations. • Incorporate environmental performance considerations in the government's procurement decisions. • Government-funded new residential construction will meet GreenHome energy efficiency standards. • Government-funded commercial and institutional, construction and renovation will meet or exceed the LEED Certified Standard for energy efficiency. • Improve energy efficiency and reduce the greenhouse gas emissions of the government's light vehicle fleet. • Implement an environmental stewardship initiative for the Department of Education and Yukon schools. • Establish 'green action committees' in all departments. • Conduct an energy analysis of all Yukon government buildings and complete energy saving retrofits. • Develop best management practices for industry to reduce GHG emissions. • Develop pilot projects to demonstrate home and commercial energy efficiency and heating technology. • Improve access to home energy evaluations by providing evaluator training.

Goal	Strategies
	• Develop wood energy opportunities for residential and institutional heating.
Lead Yukon action in response to climate change.	• Forecast potential future GHG emissions for Yukon. • Work with federal partners to ensure national GHG inventory is accurate and consistent for Yukon. • Set a Yukon-wide emissions target within two years. • Create a Climate Change Secretariat. • Determine the potential of a Yukon carbon economy. • Incorporate climate change considerations into government decision making. • Create a community engagement forum for taking action on climate change.

CANADIAN ELECTRICAL INDUSTRY LEVEL POLICY INFLUENCES

Yukon Energy is a member of the Canadian Electricity Association (CEA) and as such it agrees to comply with the CEA's Sustainable Electricity Program as a condition of membership[15]. This program is an industry wide initiative and each member utility is responsible for program implementation within their organizations. For the purposes of this program, the CEA has defined sustainability as "pursuing innovative business strategies and activities that meet the needs of members, stakeholders and the communities in which we operate today, while protecting and enhancing the human and natural resources that will be needed in the future." A three-pillar approach (social- environmental – economic) has been adopted to provide a more holistic approach to sustainability.

The 10 guiding principles of the CEA's program intended to help member utilities improve their overall sustainable development performance are:

1. **Environment:** Minimize the adverse environmental impacts of our facilities, operations and businesses.

2. **Stewardship and Biodiversity:** Manage the environmental resources and ecosystems that we affect to prevent or minimize loss and support recovery.

3. **Climate Change:** Manage greenhouse gas emissions to mitigate the impact of operations on climate change, while adapting to its effects.

[15] Full details about this program can be found on the CEA website (http://www.sustainableelectricity.ca).

4. **Health and Safety:** Provide a safe and healthy workplace for our employees and contractors.

5. **Workplace:** Support a fair, respectful and diverse workplace for our employees and contractors.

6. **Communications and Engagement:** Communicate with and engage our stakeholders in a transparent and timely manner.

7. **Aboriginal Relations:** Communicate with and engage Aboriginal people in a manner that respects their culture and traditions.

8. **Economic Value:** Provide economic benefits to shareholders, communities and regions in which we operate.

9. **Energy Efficiency:** Produce, deliver and use electricity in an efficient manner while promoting conservation and demand side management.

10. **Security of Supply:** Provide electricity to customers in a safe, reliable and cost effective manner to meet current and future needs.

This program is supported by a set of environmental, social and economic performance indicators that member utilities report on annually to CEA[16].

YUKON ENERGY CORPORATE PRIORITIES

Yukon Government policies that along with the Industry Level Policy Influences have impacted in a material way Yukon Energy's strategic priorities[17] include:

- Optimizing existing infrastructure to improve system reliability and efficiency;
- Developing clean energy solutions to meet growing demand; and
- Engaging Yukoners to better meet future energy needs.

YUKON PUBLIC ENGAGEMENT IN ENERGY PLANNING

As part of Yukon Energy's multi-year public awareness campaign, the corporation completed two public and stakeholder opinion surveys in June 2010 and in early 2011.

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[16] A public advisory panel exists to provide an independent opinion to the CEA Board of Directors on the implementation of the program and program implementation will be verified by an external verifier.
[17] Yukon Energy Corporation (2011). 2010 Annual Report. Available at http://www.yukonenergy.ca.

The 2010 surveys were designed to understand what Yukoners and the business community knew about the Corporation[18]. Over 600 people took part in the 2010 surveys and the following trends emerged:

- Yukoners understand that hydro-generated electricity is the mainstay of power generation in the Yukon, but strongly support the development of alternative energy sources to supplement hydro.
- Yukoners are looking to Yukon Energy to bring forward creative ideas in meeting future energy needs.
- Yukoners strongly support the need for energy conservation and see this as a shared responsibility among the public, the business community and industry.
- While Yukoners have confidence in Yukon Energy's ability to plan, develop and manage the territory's energy needs, there is concern that politicians and vested interest groups can be detrimental to effective, strategic, long-term planning.
- Yukoners want to remain engaged in the discussion around the territory's energy issues and the Yukon Energy's objectives for a clean energy future.

The findings from the first surveys helped Yukon Energy design a public awareness campaign to give Yukoners a better understanding about who Yukon Energy is, what the Corporation is trying to achieve, and why.

The 2011 survey consisted of telephone and online surveys and "pulse polls"[19] targeting the general public and the business community. Many of the questions paralleled questions asked during Phase I to identify changes in knowledge, awareness and views of Yukoners concerning energy related issues. High response rates for the surveys indicate that Yukoners are significantly engaged and interested in energy related issues.

Although there are varying levels of awareness regarding the different resource development projects being considered, there is a general recognition that strategies are needed to increase energy production to meet future demand and that the industrial sector will be the big energy consumer.

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[18] The Phase I survey was designed to establish benchmark indicators among target audiences to assess and evaluate knowledge of Yukon Energy and awareness of energy related issues. The research model was built in a knowledge, awareness, and behaviour (KAB) evaluation design. This design begins by testing current knowledge levels, assessing any change in awareness levels over time (e.g., as a result of educational or communications intervention) and determining whether there are any increases in knowledge or changes in beliefs or expectations.

[19] Pulse polls are online questions designed to gather quick "top of mind" responses to a few key issues. These polls were published in the online edition of the Yukon News and on the Yukon Energy website.

Other trends identified include:

- A strong preference for alternative energy and increased energy conservation measures;
- The majority of respondents indicated that expanding alternative energy or a mix of alternative and hydro generation were preferred;
- Only two percent of respondents preferred to expand diesel generation capacity; and
- The issue of paying for alternative energy received a mixed response. While a majority of survey respondents were willing to pay more for alternative energy the majority of "pulse poll" respondents were not willing to pay more than they are currently[20].

2011 RESOURCE PLAN & MARCH 2011 ENERGY CHARRETTE

To enhance public understanding of resource planning issues, Yukon Energy engaged Yukoners (along with national and international recognized energy experts) in a three day Charrette planning process in Whitehorse in March, where Yukon's energy demand situation and potential opportunities, both near-term and long-term, were reviewed. A cross-section of Yukoners representing various interests was invited to participate in the three day process.

Prior to the Charrette, community meetings were held in three Yukon communities (Mayo, Dawson City and Haines Junction) to learn about electrical energy concerns at the community level. In addition, stakeholder interviews were carried out involving approximately 50 individuals and representatives from a broad array of organizations, agencies and government departments[21].

The Charrette resulted in the development of four energy planning principles[22]:

- Reliability;
- Affordability;
- Flexibility; and

[20] The results of the business surveys indicated increased confidence in Yukon Energy's ability to assess future energy needs. Business/ community leaders also expect the availability of power to get worse within the next five years. There was some willingness to pay more for renewable energy with 10 percent saying they would pay one to two percent more and 42 percent willing to pay up to five percent more.

[21] The Charrette's expert background reports, presentations, summaries of community and stakeholder consultations and summaries of the Charrette are all available on Yukon Energy's web site.

[22] A more complete discussion of these principles can be found in Section 1.

- Environmental Responsibility.

Yukon Energy has committed to continue engaging Yukoners in resource planning, including an opportunity to comment on the draft 2011 Resource Plan. To this end, a draft 2011 Resource Plan has been prepared for public comment.

In addition to the principles, the participants talked about energy ideas discussed with experts and each other. They learned about the Yukon's planning realities, the resource planning options and the risks and uncertainties which make planning for Yukon's energy future challenging.

From the beginning Yukon Energy set out to engage Yukoners to find the answers together. Outcomes of the Charrette include:

- Yukoners are talking about energy;
- Yukoners have a better understanding of Yukon Energy planning realities and future resource options;
- Yukon Energy has energy resource background papers specifically prepared considering the Yukon context for hydro, demand side management, biomass, wind, natural gas, diesel, coal and thermal, waste to energy, storage and transmission, nuclear, geothermal and solar;
- Yukoners learned that the obligation to serve is a risk and uncertainty that other utilities across Canada share and plan for;
- Yukoners want energy decisions to consider more than just cost;
- Future energy options must be affordable, reliable, flexible and environmentally responsible;
- Energy conservation must be considered as the key resource planning option in the short-term;
- Along with exploring new hydro, hydro enhancements, wind at Ferry Hill, geothermal and waste to energy, Yukon Energy should also investigate possible options such as biomass, wind, solar and liquefied natural gas;
- Yukon Energy should explore the local beetle kill forest as fuel for biomass;
- Yukon ratepayers may need to pay more for their electricity if the rates are to better reflect the true cost;
- The next 20-Year Resource Plan must reflect what was heard at the Charrette;

- Yukon’s youth (as represented by Experiential Science 11) want to be engaged and part of Yukon’s energy solution; and
- Yukon Energy must continue to work with Yukoners to find the answers together.

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1.1 RESOURCE PLANNING PRINCIPLES FOR YUKON

(i) Overarching YG Energy Policy[23]

The Yukon Government's *Energy Strategy for Yukon* sets out a vision and principles for Yukon that includes development of a "sustainable and secure energy sector that is environmentally, economically and socially responsible". The *Energy Strategy* recognizes that "investment in electricity infrastructure will leverage economic development for the territory" and renewable energy infrastructure will "enhance the kinds of long-term legacy benefits that are currently enjoyed with the existing hydro system," and serve to "buffer Yukon's energy sector from volatile fossil fuel prices and help to minimize greenhouse gas emissions from diesel generated electricity".

(ii) Key Yukon Electricity Resource Planning Principles

The March 2011 Charrette participants agreed on the fundamental importance of four key principles for electricity resource planning in Yukon:

1. **Reliability**[24] – Reliable supply for power utility customers today and in the long-term. This includes short-term reliability to keep the lights on, ensure sufficient supply to meet winter peak loads (reliable capacity), and minimize the number and duration of any power outages. When assessing new resource options, reliability includes security of the resource supply and the ability to develop new resource options in a timely manner as needed to meet near-term requirements in a cost effective manner.
2. **Affordability** – Minimize electricity costs for customers today and in the long-term[25].
3. **Flexibility** – Flexibility to deal with major and sudden changes in grid loads. In light of ongoing load uncertainties, new resource supply options need to be resilient and robust under various potential load scenarios[26].

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[23] See Preface for a more detailed review of YG policy context for the Resource Plan.
[24]Yukon Energy's 2010-12 Strategic Plan notes, "the first strategic priority is to improve system efficiencies and system reliability. New investments and procedural changes are being put in place. In the next two to five years we hope to achieve a seventy-five percent reduction in controllable outages (unplanned and not caused by nature)".
[25] The Yukon Utilities Board regulates the costs to be recovered through rates, focusing on need, justification, and the reasonableness of costs incurred – and with a clear objective to minimize the costs required to serve customers today and in the future.

4. **Environmental Responsibility** – Responsibility with regard to local and global socio-economic impacts and environmental impacts on land, water, and air. This principle includes, but goes beyond, responsible planning to mitigate and manage socio-economic and environmental impacts as required by various regulatory authorities. Yukon Energy is committed to plan for energy solutions that reduce greenhouse gas emissions (GHGs), and meet Yukon, national and global climate change action plans[27], and that follow the Yukon Government's Energy Strategy. That strategy "supports a shift towards cleaner, renewable sources of energy", and seeks to increase energy production from renewable resources and reduce fossil fuel use and GHG emissions through replacing fossil fuels with cleaner, renewable energy sources[28] where possible[29].

Additional principles noted at the Charrette included provision for local jobs and energy security – where feasible, there was a preference to utilize resources that were locally available (e.g., wood biomass such as beetle kill timber near Haines Junction) as well as technologies that Yukon is familiar with (e.g., Hydro).

(iii) Challenge of Balancing Key Principles

In applying these key principles, no one principle takes precedence or is given greater weight than any other. The objective is to achieve an appropriate balance within the existing Yukon policy framework[30] using professional judgment based on Yukon realities and reasonably forecast near-term and longer-term requirements.

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[26] Resource planning must be attentive to the reality that loads will not grow at continuous rates in the future but (as experienced in the past) will likely come on and off the system in lumps to the extent that mine loads are connected to the grid. Because Yukon is not interconnected with grids in other provinces/jurisdictions, surplus energy in Yukon cannot be exported, and Yukon needs also cannot be met through energy imports. This reality means that sudden loss of mine loads can therefore result in major rate increases for the remaining customers to the extent that ongoing fixed generation or transmission costs remain to be funded. Sudden addition of new mine loads can also result in major rate increases for all existing customers to the extent that no surplus renewable resources can be utilized and lower cost new supply options are not readily available.

[27] Yukon Energy's Strategic Plan: 2010-2012 notes, "our next priority is to meet demand with clean energy". Yukon Energy's 2010-12 Strategic Plan also notes "Renewable sources include hydro, wind, geothermal and solar and some potential clean sources include biomass and natural gas." "It is essential that Yukoners continue to use oil and gas resources efficiently and replace them with cleaner or renewable energy sources whenever it is practical to do so."

[28] Renewable resources in this respect include: hydro, wood, wind, solar and geothermal energy sources. Natural gas is considered to be a "cleaner" energy resource.

[29] Yukon Government's Energy Strategy notes, "the Yukon government recognizes that oil and gas will continue to be a significant component of Yukon's energy mix and energy resources for the foreseeable future", "the government is committed to ensuring the oil and gas sector will deliver optimal benefits to Yukon" and " will encourage the use of Yukon's resources to replace imported produces" as part of "overall efforts to rely on local energy sources where possible to ensure a stable and secure supply of energy for Yukon."

[30] This includes Yukon's Energy Strategy and the Yukon Climate Change Action plan and any other relevant government policies or directions, as well as Yukon Energy's Strategic Plan.

As Dr. Mark Jaccard noted during the Charrette:

> "Like other jurisdictions, Yukoners want energy services that are affordable, reliable and environmentally responsible. But the Yukon's isolated grid and the substantial but uncertain energy needs from mining activity mean that energy system flexibility has a high value in Yukon too."

1.2 CAPACITY AND ENERGY PLANNING CONTEXT

As the main generator and transmitter of electrical power in the Yukon region, Yukon Energy plans the capacity and energy electric power requirements:

- **Capacity planning** - Focuses on the highest or peak megawatt (MW) generation capability (capacity) required on each system during each year, including sufficient reserve capability (based on the system's capacity planning criteria) to address generation and transmission unit breakdowns.
- **Energy planning** - Focuses on the number of kilowatt hours (kW.h) of electricity that are required to be generated over the course of a year on each system.

The 2011 Resource Plan develops a roadmap that guides Yukon Energy's ability, working with others, to develop clean and renewable legacy generation and transmission resources while effectively addressing current power needs[31]. Consistent with Yukon Energy's 2006 Resource Plan, the plan focuses on near-term requirements and longer-term opportunities (to be addressed during the next five years) as follows:

- **Near-term requirements by 2014** - Yukon Energy generation and transmission commitments required before the end of 2014 for major investments with anticipated costs of $3 million or more. Given the time needed for possible construction, this assessment examines possible in-service needs to meet loads to 2017.
- **Longer-term opportunities before 2021** - Appropriate Yukon Energy planning activities required during the next five years to protect longer-term legacy resource development options for potential start of construction *before* 2021.

[31] The 2006 Yukon Energy 20-Year Resource Plan addressed major electrical generation and transmission requirements and options in Yukon during the 2006-2025 period, focusing on Yukon grids. It was reviewed and recommended by the Yukon Utilities Board in its January 2007 Report to the Minister. One of the Board's recommendations was that the 2006 Resource Plan be updated every five years.

- **Longer-term opportunities after 2021:** Appropriate Yukon Energy planning activities required during the next five years to protect longer-term legacy resource development options for potential development *after* 2021.

1.3 CHARACTERISTICS OF EXISTING YUKON GRID

The new integrated grid, including the new Mayo B and Aishihik 3rd Turbine hydro units, has 142 MW of installed generation of which approximately 77 MW can be relied upon for the winter peak.

The existing diesel infrastructure[32] is utilized today primarily as reserve capacity to meet peak or short-term emergency needs - however, it remains available as well to provide baseload energy as required[33]. Although the grid has ample diesel infrastructure to supply reliable energy when hydro capability is fully utilized, reliance upon diesel generation to supply energy requirements in excess of hydro capability has high cost and emission impacts. Accordingly, a primary focus of the Resource Plan is the examination of more affordable and environmentally responsible supply options which have the capability to displace diesel energy generation.

Key features of the current Yukon system include:

- Current Yukon population is approximately 35,000[34], roughly 76% of whom are in Whitehorse. The small population means there is a lower overall ratebase over which to share costs of facilities required to meet growth on the system (whether those costs are due to need for increased baseload diesel or new renewable generation).

- Over 94% of the Yukon population is served today by hydro generation on the Yukon Energy hydro grids (Integrated System grid now includes Whitehorse-Aishihik-Faro [WAF], Carmacks-Stewart [CS], and Mayo-Dawson [MD] transmission). Watson Lake, Destruction Bay, Beaver Creek, Swift River and Old Crow are each served by Yukon Electrical's isolated diesel generation.

- Diesel generation facilities account today for 57% of reliable utility capacity to serve the grid winter peak and all of utility capacity for the five separate off-grid diesel communities served by

[32] The existing diesel infrastructure is reviewed in Appendix A.
[33] At 90% capacity factor the existing 44.2 MW of grid diesel capacity could potentially provide almost 350 GW.h per year of electricity.
[34] Yukon Bureau of Statistics, June 2011 –Yukon population estimated at 35,175; Whitehorse population at 26,711 or 75.9% of Yukon population.

Yukon Electrical. Diesel generation also currently supplies off-grid industrial mine projects (e.g., Wolverine mine) not supplied by Yukon power utilities.

- The Integrated System grid is isolated from grids outside of Yukon such as BC and Alaska.
  - The isolated nature of the existing Yukon grid system means that when large industrial loads come on and off the grid system there can be material electric utility revenue and cost impacts, and therefore rate impacts for other customers. In the past, due to the historic investment in material capital intensive assets mine loads (e.g., Faro mine or UKHM) leaving the system led to material rate impacts and surplus hydro generation.
  - The isolated nature of the Yukon grid also prevents any export sale of surplus Yukon renewable generation or import of electricity when Yukon supplies are constrained, and therefore careful attention must be paid to matching the development opportunity with forecast loads.
  - This Yukon reality is significantly different than exists with southern grids such as in British Columbia[35].

Continued reliance on the existing grid system to deal with load growth means, unless other viable alternatives are found, an increasing need to rely on more costly diesel generation to meet energy loads over the near and longer-term.

- The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, means that other forms of backup capacity are required to supplement available hydro to meet the system's winter/spring seasonal generation constraints, and to provide reliable energy generation in drought years.
  - **Winter constraints** - Seasonal water storage is typically needed for hydro facilities to be fully utilized in winter. In Yukon, controlled seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but is largely unavailable at Whitehorse. As a result, there is an increasing need to rely on diesel generation to meet baseload energy loads in winter and early spring when grid loads are highest and hydro water flows are constrained.

[35] Inability to market surplus renewable generation, for example, constrains Yukon ability to accommodate in a cost effective way long-term renewable resource contracts with independent power producers (IPPs) in the same way as such arrangements are made in British Columbia, and means that such long-term contracts may not fit easily with the current requirements of the Yukon system.

- **Summer constraints** - In contrast, until loads increase to much higher levels, little if any diesel generation is likely to be required during summer and fall when the Whitehorse hydro units actually have surplus hydro generation (because of lower loads and high water levels from summer fall runoff).

  These system characteristics undermine the cost effectiveness of capital-intensive renewable resource options to displace diesel generation, unless such options focus their new generation in winter (i.e. generation from these resources are not needed and therefore cannot be utilized in the summer and fall because of the surplus hydro that exists on the system).

- **Drought-flood year constraints** - In addition to seasonal supply constraints, systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to drought (low water) conditions, and in these circumstances hydro generation must be supplemented by other reliable forms of generation[36]. Hydro-based systems must also anticipate flood (high water) conditions (where the need to rely on other reliable forms of generation will be greatly diminished or eliminated).

  This high variability based on available water in combination with the isolated nature of the Yukon Grid undermines the cost effectiveness of capital-intensive renewable resource options developed to displace diesel generation unless they are flexible to this inherent hydro based system variability.

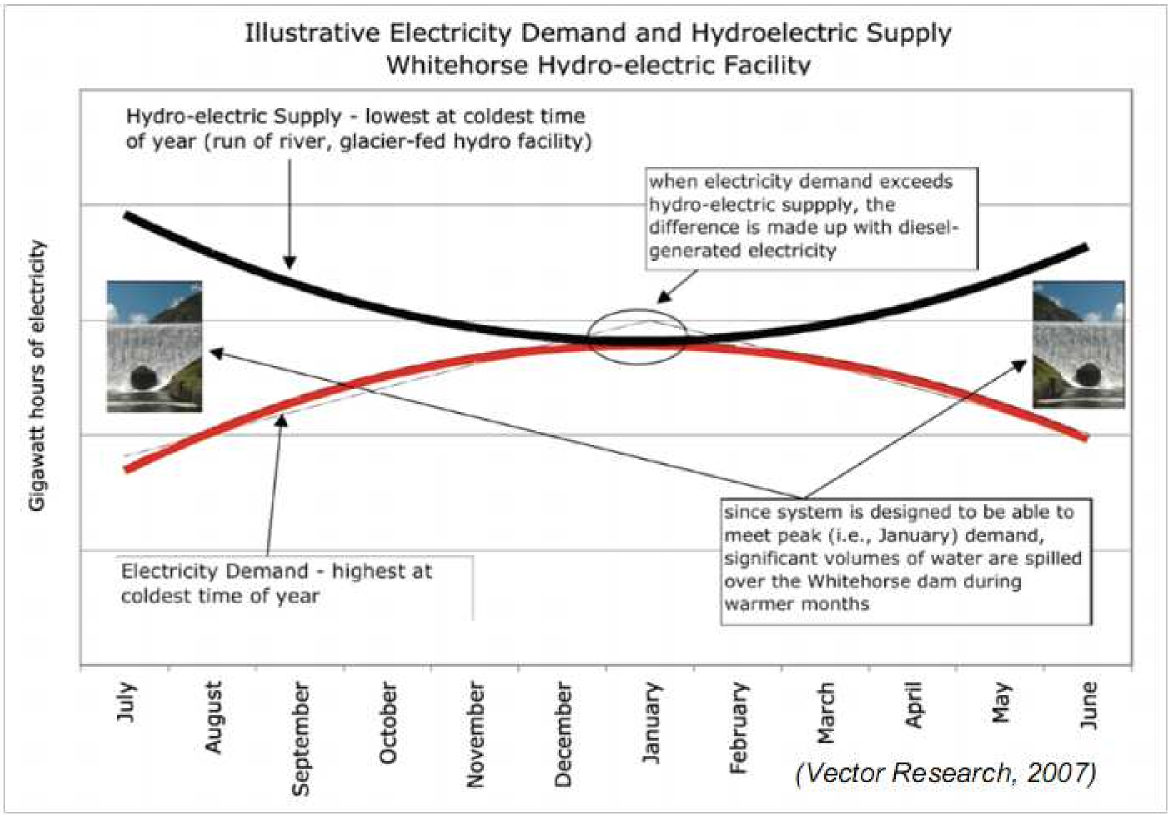
Accordingly, assessments of the viability of diesel displacement opportunities must fully consider these constraints.

Figure 1-1 highlights the widely varying seasonal levels of demand and hydro supply at the Whitehorse generating facility[37]. Winter, which is in the middle of the figure, shows that when demands tend to peak the hydro supplies at Whitehorse tend to be most constrained.

[36]The requirement for thermal resources to back up hydro resources exists even in interconnected systems such as Manitoba (which continues to include a small amount of thermal generating resources in its power resource plan) and British Columbia (e.g., the Burrard generating station).

[37] Seasonal hydro storage can enhance winter hydroelectric generation at Aishihik and Mayo generating facilities relative to Whitehorse – but the overall seasonal swings of demand and hydro supply remain a key feature of the existing Yukon grid system.

Figure 1-1: Illustrative Seasonal Electricity Demand and Hydroelectric Supply



Under the Public Utilities Act and related regulatory principles Yukon Energy has an obligation to serve all customers that seek service within its franchise area. In relation to industrial customers this obligation is subject to certain limitations i.e., Yukon Energy is not required to serve a new industrial customer unless that customer is prepared to fund directly the interconnection costs and risks required for Yukon Energy to connect the new load to the grid[38]. As a result, new major industrial customers located far from the current grid would in all likelihood not be added to the Yukon system primarily because of the costs of interconnection. In those circumstances new major industrial loads would typically be supplied by isolated

[38] Following the 2006 Resource Plan review by the YUB, Yukon Energy has received YUB approval for Power Purchase Agreements (PPAs) for the Minto mine and the Alexco mine - these PPAs have established a range of new measures to manage risks related to serving new industrial customer connections to the grid, including those noted here and in Appendix B. Similar PPAs would be required prior to connecting future potential mines such as Victoria Gold and Carmacks Copper (in the case of Carmacks copper, a material contribution would also be required towards the capital costs incurred for the Carmacks-Stewart Transmission Project). Appendix B also reviews other measures that Yukon Energy has adopted in the past to manage ratepayer risks related to development of legacy renewable resources on the grid, including flexible debt financing to manage overall load shift impacts on capital costs charged to ratepayers, third party financing to reduce ratepayer impacts related to such capital investments, and special funds used to manage other utility risk related to changes in circumstances (e.g., low water/drought risks and diesel fuel price variability risk).

on-site diesel generation with all costs excluded from YUB consideration in rate setting for utility customers served on the grid or in off-grid communities.

In addition to these Yukon system realities the planning context within which the 2011 Resource Plan is being developed is also materially different than in 2006.

- The WAF capacity shortfall that was pending in 2005 has been addressed. The capacity of the interconnected WAF and MD grids is now more than adequate to serve current winter peak loads[39].
- Since 2005, the material hydro surplus has been nearly fully utilized because of greater than expected non-industrial load growth, and the interconnection of the Minto (2008) and Alexco (2010) mines[40].
- Since 2005/06, most of the hydro enhancement opportunities identified in the 2006 Resource Plan or in 2007/08 Yukon Energy studies have now been either developed or are currently under active consideration. As a result consideration is required of new renewable resource supply options so that diesel energy generation is not by default relied upon to meet increasing future incremental loads. Pursuing new greenfield resources limits supply options available in the near-term, and requires extensive planning through the next five years to protect any priority new legacy renewable clean resource supply options that might be needed or preferred by 2021.

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[39] Yukon Energy's 2006 Resource Plan proposed new generation capacity planning criteria, and forecast significant WAF generating capacity shortfalls based on these criteria as early as 2007 and 2008. To address these winter peak generating capacity shortfalls, a planning sequence was set out in the 2006 Resource Plan proceeding that secured cost effective options for up to 25.4 MW of WAF capacity in a staged and flexible manner comprised of recommissioning a 5 MW Mirrlees unit at Faro, acquisition of 6.4 MW of diesel units at Minto, plus staged refurbishment of up to three Mirrlees units at Whitehorse (totalling 14 MW) over the period to 2012. With the 2008/2009 GRA (and Order 2009-8) YEC has determined not to proceed with the purchase of the Minto diesels.

[40] In 2005, surplus hydro generation on WAF prior to secondary (interruptible) sales approximated 90 GW.h/year at normal flows. The 2006 Resource Plan forecasts indicated that at normal flow levels (i.e., average hydro energy generation) absent new industrial loads, some surplus hydro was forecast to remain on both the WAF and Mayo Dawson ("MD") grids until at least around 2020. Diesel generation was not forecast to be required to supply sustained loads (i.e., loads in excess of average annual hydro energy generation) until the 2020 timeframe, increasing to about 28 GW.h/year in 2025. It was also noted that some diesel generation would be required for peaking purposes (i.e., brief time periods during the winter peak months), but these peaking diesel generation requirements were forecast to remain below 10 GW.h per year until after 2020 (i.e., near the end of the 20-year planning period).

1.4 CURRENT RESOURCE PLANNING CHALLENGES & OPPORTUNITIES IN YUKON

The following resource planning challenges were noted in the Yukon Energy 2011 Charrette Report:

- **Need for new supply to meet future growth** - Yukon must plan and build new supply for new electricity demand that supports economic growth within the reality of high diesel prices and limited short-term alternatives other than diesel generation. The challenge is to determine how increases in demand driven by economic growth can be turned into opportunities to create a supply of clean or sustainable energy that Yukoners can afford and support.

- **Need to provide safe and reliable service in a cost effective manner** - Regulatory rules that exist tend to be confusing and complex. Most people do not know the true cost of electricity and expect that they should continue to receive low cost power. While Yukoners have enjoyed and come to expect low cost power, a key theme of the Charrette (enforced by speakers from outside the Yukon) was that utilities across Canada are all expecting material increases in the cost of supply and this will impact rates[41]. The challenge for resource planning in all jurisdictions including the Yukon is to ensure future supply options remain affordable and do not unfairly burden ratepayers[42].

- **Need for flexibility to address challenges related to the isolation of Yukon's electricity system** - As noted by Dr. Mark Jaccard during the Charrette, "Yukon's isolated grid and the substantial but uncertain energy needs from mining activity mean that energy system flexibility has a high value in Yukon" in addition to values such as affordability, reliability and environmental responsibility.

- **Need to pursue new sources of generation in a manner that promotes environmental responsibility** - Generation of power must be done with the least amount of impact on the environment. This includes the need to avoid, as much as possible, the production of greenhouse gases. Renewable energy is attractive but can be expensive in the short to medium term. Hydro can impact the environment through flooding. How can we plan for future energy needs in a

[41] The Charrette presentation of Pierre Guimond indicates in 2009 total capital investment in the electric power sector at $16 billion with a further significant capital investment requirement (up to $237.6 billion). The presentation notes that of the $237.6 billion (in 2007 CDN dollars) $88.3 billion is expected to be spent over the period form 2007-2015 and $149.3 billion is expected to be spent over the period from 2016 to 2030. The presentation also notes over the period from 1998 to 2009 average electricity prices have increased by $1.05/KW.h (in 2008 c/KW.h and based on 1000 KW.h monthly consumption), underlining the new costs pressures in this sector throughout Canada.

[42] As with other Canadian power utilities, Yukon Energy is also required to undertake major investments to maintain its current system, replace assets, enhance system reliability, and plan for potential new resource supply developments.

more integrated way that takes into account ideas such as district heating, reduction of transportation fuels, minimizing environmental foot prints, renewable energy and the use of local resources[43]?

These resource planning challenges and the unique characteristics of the Yukon System underline the additional challenge of determining how increases in demand driven by economic growth can be turned into an opportunity to create a supply of clean or sustainable electricity that Yukoners can support and afford. Higher costs to secure new grid supply will impact rates for all utility customers. Higher GHG emissions from new generation will hamper Yukon's ability to secure overall GHG emission reductions, whether or not the new demand occurs on or off the grid.

Accordingly, although the existing grid has sufficient capacity and energy capability to meet near-term load requirements[44], until such time as other affordable and environmentally sensitive supply options can be developed non-industrial and industrial load growth will increase baseload diesel generation with consequent added upward pressure on utility costs (and therefore rates) and GHG emissions.

- For example, with current and committed grid resources and no development of new supply options, a 2015-2016 grid load forecast at 545 GW.h[45] will require 101 GW.h of baseload grid diesel generation (as compared to a forecast 2 GW.h of baseload grid diesel at forecast 2011 loads) which could be supplied by existing diesel generation resources.
- This level of diesel generation at current approved Hydro zone diesel generation costs (30 cents/kW.h) would add approximately $30 million operating costs to utility rates. After considering related revenue growth from such increased loads, the average net rate impact for all utility ratepayers would potentially be almost 6 cents per kW.h.
- This level of new future diesel generation would also increase future Yukon GHG emissions by 70,000 tonnes per year, whether or not the new demand occurs on or off the grid.

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[43] Pierre Guimond President and CEO, Canadian Electrical Association noted during the Charrette that, "cost-effectiveness, reliability, and safety are the pillars on which the Canadian electric power system was built. A new constant, sustainability, is one of the key driving forces behind the transformation that will occur in the decades to come. The future industry will take into consideration the balance of environmental, social, and economic impacts, which the system will have on Canadians."
[44] Subject to the need for added diesel capacity to meet capacity planning requirements (due to retirements and new mine loads).
[45] A 545 GW.h/year grid load in 2015 would be is only very slightly higher than the forecast for that year with Victoria Gold (Eagle Gold mine) connected, without any impacts from future DSM/SSE.

Today Yukoners derive material benefits from past investment in legacy transmission and generation infrastructure developed in response to major industrial loads[46]. In the past, Northern Canada Power Commission and Yukon Energy (since 1987) successfully pursued legacy investments that have provided low cost and renewable power over the long-term for Yukon ratepayers. These environmentally responsible energy investments were characterized by higher costs over the short-term (when capital costs in the early years result in high amortization costs), and low and stable costs over the long-term.

Planning activities for the Yukon grid must continue to address the challenges arising from sharp changes in load when major industrial loads are connected or are shut down:

- For example with connection of Victoria Gold (Eagle Gold) an increase in grid load of 103 GW.h/year is forecast in 2015-2016 (from 442 GW.h/year to 545 GW.h/year), excluding any impacts from new DSM. This will - with current and committed grid resources - increase diesel generation by about 76 GW.h/year (and the reverse would occur when the mine life expires).
- With the additional connection of Carmacks Copper and Whitehorse Copper a further increase in grid load of 65 GW.h/year is forecast in 2015-2016 (from 545 GW.h/year to 610 GW.h/year). This will further increase diesel generation by about 59 GW.h/year (and the reverse would again occur when the mine's lives expire).

Unlike many other supply options, existing diesel generation is highly flexible to increases or decreases in grid loads. Therefore, alternative new supply options -- to be viable -- will also need to be very sensitive to the extent and duration of the loads that are used to justify such investments. New greenfield legacy hydro developments, for example, require many years for planning, i.e., planning over the next five years is needed if such an option is to be protected for in-service by 2021 – and once developed, grid load levels sufficient to ensure effective utilization of such a capital intensive resource are required for 30+ years.

Managing these risks is required to develop over the long-term new renewable legacy projects so that Yukon load growth can be met with resource options that are lower cost (and more environmentally responsible) than diesel generation.

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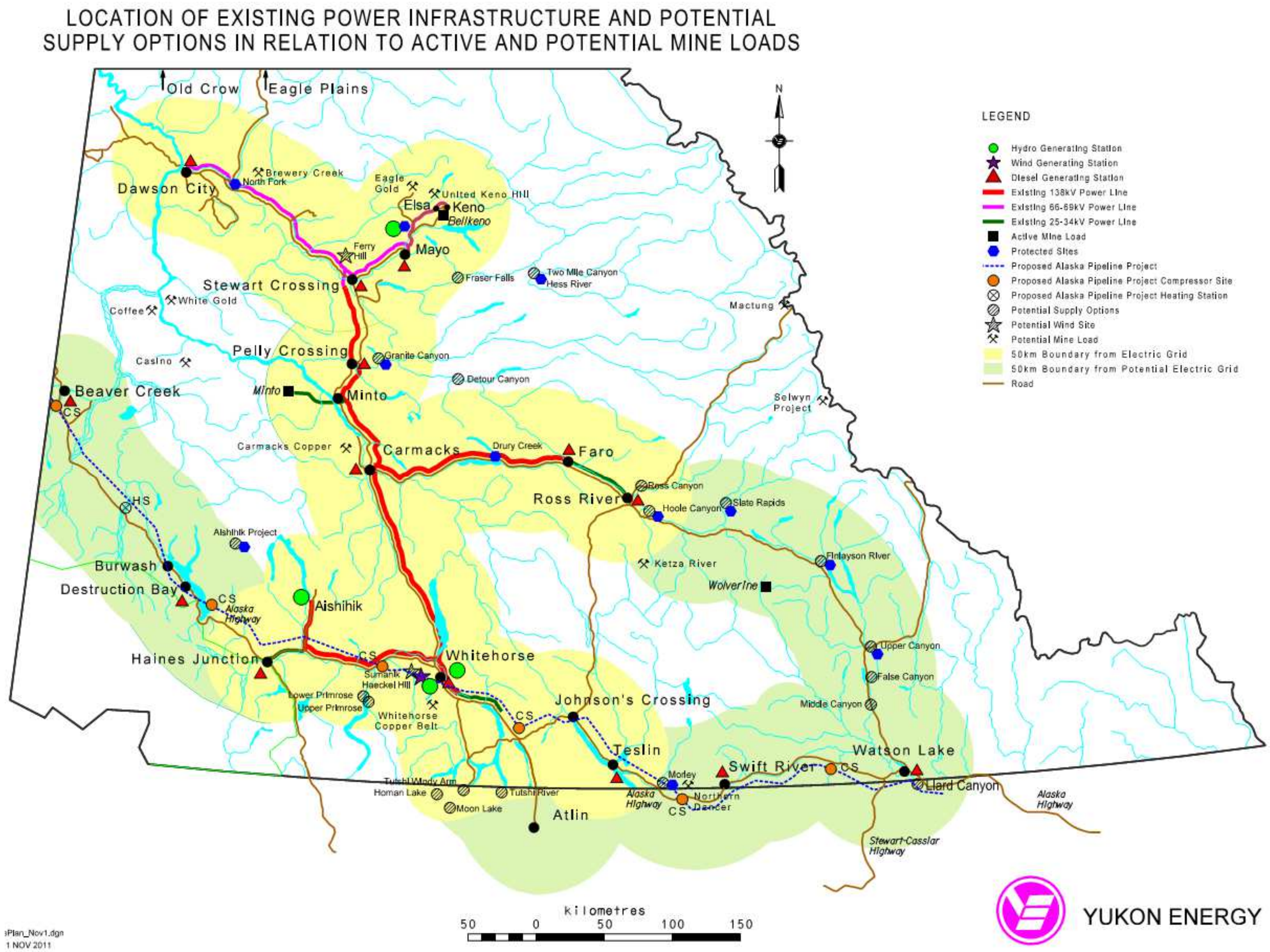
[46] Legacy renewable power assets are long-lived and capital intensive renewable resource investments with low operating costs. Legacy or heritage renewable hydro investment in the past has yielded these benefits in Yukon and in other jurisdictions in Canada such as British Columbia, Manitoba and Quebec.

The existing power infrastructure, active and potential mine developments, the potential Alaska Highway Pipeline, and future power supply options in Yukon over the resource planning period are detailed in Figure 1-2 below. This provides an overview of specific renewable resource locations examined in the 2011 Resource Plan within the context of the current integrated grid power supply infrastructure and the diverse range of industrial development opportunities that could develop in the Yukon during the 20 year planning period. Figure 1-2 indentifies areas within a 50 km boundary from the current and potential future electric grids (based only on the current southern highway structure).

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



2.0 FORECAST LOAD REQUIREMENTS & CHALLENGES

Section 2 reviews forecast electrical load requirements in Yukon over the 20-year planning period and beyond, as well as capacity and energy related challenges for the existing grid under these forecast loads.

Load forecasting is a key component of the Resource Plan, providing one foundation for assessing the need and justification of the resource planning options reviewed in Sections 3 through 6.

- Near-term forecast load requirements for the grid, for example, define the opportunities for near-term major project options to be committed before 2015 and the extent to which such new resources may continue to be utilized effectively over the 20-year planning period. Capital intensive options that are technically feasible in the near-term were shown in the Charrette to pose major risks to ratepayers unless the load requirements to justify them are reasonably likely to be sustained through the 20-year planning period.

- Longer-term potential load requirements (off as well as on grid) define opportunities for Yukon to develop legacy renewable resource projects. Credible load opportunities within the planning period are a prerequisite for the major planning budgets required to pursue longer-term greenfield renewable options during the next five years.

In addition to defining specific near-term load growth challenges, the 2011 Resource Plan identifies potential load opportunities in Yukon within the planning period that are appropriately large and sustained to play a determinative role in defining legacy planning measures that could merit serious consideration today for Yukon Energy. As a consequence, ongoing planning activities are discussed in Sections 5 and 7 to examine potentially beneficial opportunities beyond the near-term to work with major new off-grid mines and/or pipeline developers to explore potential new legacy renewable power asset developments by 2021.

Section 2 includes the following subsections (detailed supporting information is provided in Appendices C and D):

- Background and Context;

- Overview of Potential Yukon Loads: 2011-2050;

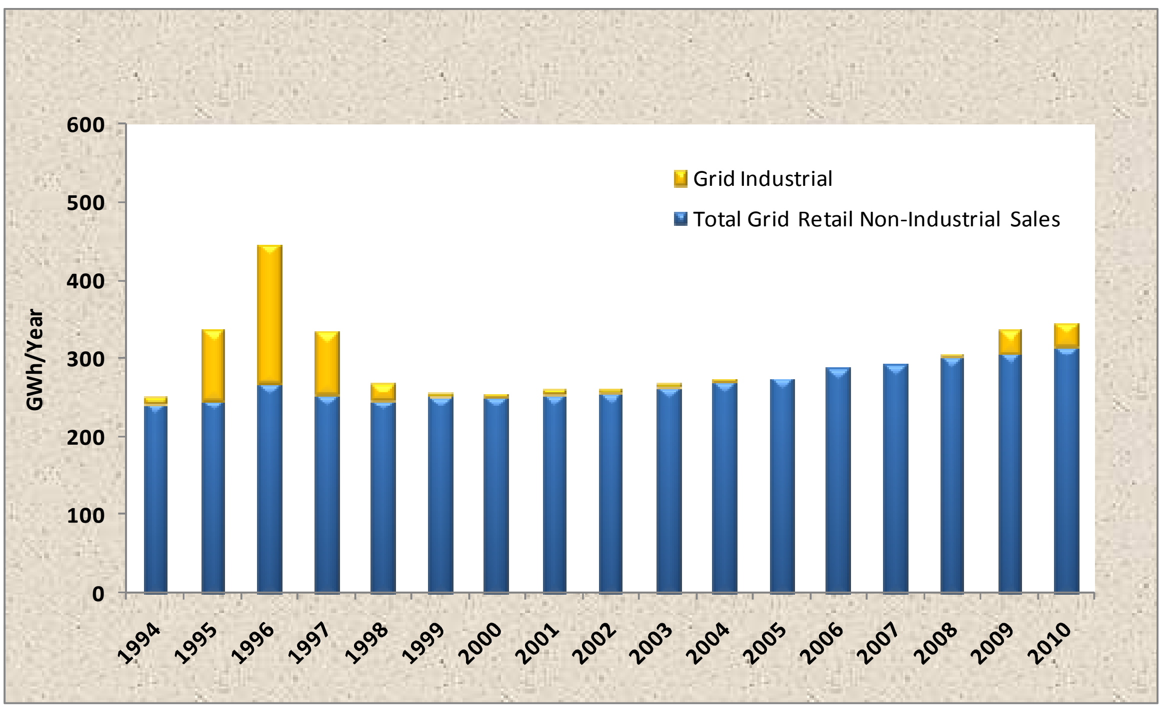
- 2011 Resource Plan Grid Load Scenarios: 2011-2030; and

- Capacity & Energy Related Challenges for Existing Grid Under Forecast Loads.

2.1 BACKGROUND AND CONTEXT

The scale of industrial load today on the existing system, and balance of industrial and non-industrial load on the current system, may be contrasted with the system in 2005 (when no industrial customers were present on the system) and with 1996/97 (when the Faro mine was operating). As reviewed in Figure 2-1, the closure of the Faro mine reduced industrial loads by nearly 200 GW.h a year, but it also dramatically reduced the loads in communities local to the mine (such as Faro, which reduced from an average residential customer count of 478 in 1996 to an average of 189 in 2001) and in major centres such as Whitehorse (Yukon Energy wholesales to YECL declined from 232 GW.h in 1996 to 217 GW.h in 2001). During this 1998-2001 period out-migration of about 10% of the Yukon's population occurred (over 3,000 people).

Figure 2-1: Historical Grid Non-Industrial and Industrial Sales – 1994-2010 (GW.h/year)



Sales (GW.h/yr)*	1995	1996	1997	1998**	2000**	2005	2009	2010
Grid Non-Industrial Firm	247	267	254	254	251	273	307	314
Grid Industrial	90	179	78	17	2	0	29	30
Secondary	6	5	4	3	4	19	17	10
Losses	27	30	19	18	19	24	28	31
Total Generation	369.9	480.4	355.5	292.1	275.5	316.1	381.9	385.6

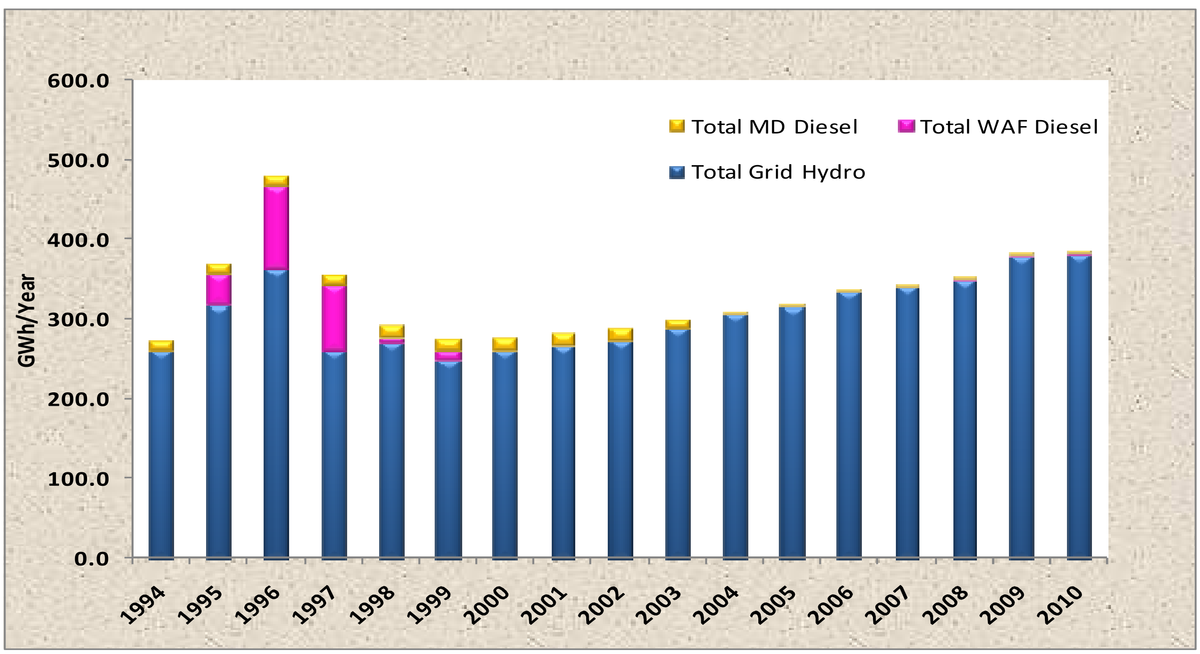
* WAF & MD loads for all years. Sales exclude energy losses required for the sales.

** Grid Non-Industrial Firm sales include (Grid Industrial exclude) Faro site dewatering sales after Faro Mine closure charged as "Industrial" prior to 2005.

Over the 2005 to 2010 period, grid non-industrial sales increased from 273 GW.h/year to 314 GW.h/year (a 41 GW.h increase over the period reflecting higher growth than was forecast in the 2006 Resource Plan). Year over year increases over the period tended to exceed the 1.85% non-industrial percentage annual growth forecast in the 2006 Resource Plan, with annual growth ranging from a 1.8% annual increase in 2007 to a 5.5% annual increase in 2006. In contrast, grid industrial sales were minimal from 1998 until 2008[47] and increased to 30 GW.h in 2010 (primarily due to connection of Minto mine in November 2008). As noted in Figure 2-1, the Minto and Alexco mine loads combined in 2010 were less than 17% of the Faro mine load in 1996.

Figure 2-2 reviews annual generation by source (hydro/wind and diesel) over the same 1994-2010 period for WAF and the Mayo-Dawson systems.

Figure 2-2: Yukon Grid Generation – 1994-2010 (GW.h/year)



Grid Generation by Source (GW.h/year)	1995	1996	1997	1998	2000	2003	2005	2009	2010
Total Grid Hydro & Wind (Incl Fish Lake)	317.5	362.3	259.6	270.3	259.5	288.3	315.5	379.3	380.5
Total WAF Diesel	39.5	104.6	81.8	7.2	0.7	0.3	0.1	2.1	2.7
Total Mayo Dawson Diesel	12.9	13.6	14.0	14.6	15.3	11.1	0.5	0.5	2.4
Total WAF & MD Diesel	52.4	118.1	95.9	21.8	16.0	11.4	0.6	2.6	5.1
Total WAF & MD Generation	**369.9**	**480.4**	**355.5**	**292.1**	**275.5**	**299.6**	**316.1**	**381.9**	**385.6**

[47] Minimal industrial loads are noted from 1999 through to the end of 2004 – these relate only to ongoing Faro dewatering activities after final shutdown of the mine. Starting in 2005, these loads became general service (non-industrial) loads.

Generation on WAF and the Mayo-Dawson systems peaked in 1996 (480.4 GW.h), with 362.3 GW.h of hydro and 118.1 GW.h of diesel generation. The highest annual generation in these areas thereafter (in 2010) was 385.6 GW.h, with 380.5 GW.h of hydro and only 5.1 GW.h of diesel generation. During the 1996 to 2010 period, resource planning activities on both grids have focused on opportunities to cost-effectively enhance the existing grid systems in order to displace higher cost diesel with lower cost surplus hydro generation available due to mine closures.

- Dawson was an isolated diesel community in 1996 and was served solely by diesel generation until September 2003[48]. Figure 2-2 illustrates ongoing amounts of diesel generation in Dawson increasing from about 12.9 GW.h in 1995 to 15.3 GW.h in 2000 and then falling to 11.1 GW.h in 2003. The completion of the Mayo Dawson Transmission Line (MDTL) interconnected the community of Dawson with Mayo (which, due to the closure of the UKHM mine in the late 1980's had material surplus hydro available). This led to a sharp reduction of diesel in the Mayo-Dawson system with diesel requirements in the range of 0.3 GW.h per year to 0.8 GW.h per year between 2004 and 2009 and 2.4 GW.h/year in 2010[49]. Hydro generation was correspondingly increased.
- When the Faro Mine was in operation, all of Yukon's WAF hydro generation was absorbed by the system and material diesel generation was required on an ongoing basis throughout the year. Figure 2-2 illustrates requirements of 104.6 GW.h of WAF diesel in 1996 and 81.8 GW.h of WAF diesel in 1997 followed by 7.2 GW.h of WAF diesel in 1998. After the shutdown of the Faro mine diesel requirements were minimal on WAF (0.7 GW.h of diesel in 2000 and 0.1 GW.h of diesel by 2005). As there were no major industrial customers on the WAF grid between 1998 and November 2008[50] there was material surplus grid hydro generation available on the WAF grid. Secondary sales were developed in the 2000 to 2005 period to provide short-term income recovery on WAF so long as surplus hydro was available.
- The CSTP Stage 1 development to connect the Minto Mine and Pelly Crossing by late 2008 established new firm load utilization for available WAF hydro generation. Although not illustrated

[48] The MD project was the first large-scale transmission infrastructure development project undertaken by Yukon Energy since the NCPC transfer in 1987.

[49] The MDTL now supplies almost all of Dawson's energy requirements and also provides lower cost grid electricity to YECL at Stewart Crossing (which was previously served by diesel generation), as well as various locations along the North Klondike Highway that were not previously served by utility power.

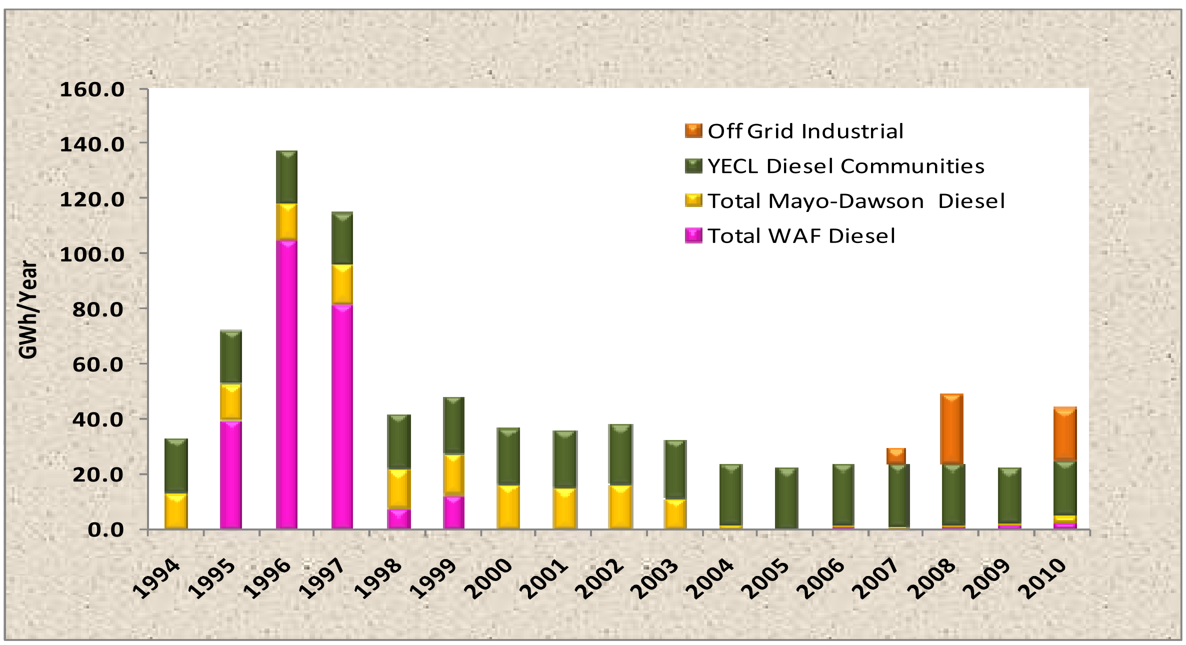
[50] After decades of operation on the WAF grid, including a number of closures and re-openings, the Faro Mine closed permanently in 1998. This mine closure followed the 1989 closure of the UKHM, which had been served by the Mayo hydro plant. Overall generation and diesel usage declined after the Faro Mine's closures in 1983, 1993, 1997 and again after its final closure in 1998.

in Figure 2-2, the interconnection and sale of surplus hydro to the Minto Mine through the CSTP directly reduced off-grid diesel requirements by about 30 GW.h and reduced GHG's by 21,000 tonnes (i.e., the Minto mine commenced commercial operation in October 2007 using its own off-grid diesel generation).

Since 2005, resource planning and development requirements for Yukon's bulk power system (i.e., grid generation and transmission) have continued to be a key focus for Yukon Energy activities. In response to new load and funding opportunities available in the period between 2005 and 2009 major new legacy resources are expected to be in place by the end of 2011, namely CSTP connection of the grids plus, Mayo B and Aishihik 3rd Turbine new hydro generation.

Figure 2-3 shows the major drop in overall Yukon diesel generation and GHG emissions after 1996-97.

Figure 2-3: Yukon Grid & Off-Grid Diesel Generation – 1994-2010 (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
Total Yukon Diesel Generation	**72.4**	**137.4**	**114.9**	**41.8**	**37.0**	**22.4**	**48.7**	**22.4**	**43.9**

*OffGrid Indusrial 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
Total Yukon GHG's	**50,684**	**96,150**	**80,453**	**29,271**	**25,892**	**15,671**	**16,609**	**15,679**	**30,726**

During the period from 2005 until 2010 off-grid communities served by YECL [Watson Lake[51], Beaver Creek, Destruction Bay, Swift River[52] and Old Crow[53]] maintained diesel generation that ranged between roughly 20-22 GW.h/year[54], and displayed minimal overall growth in utility generation (about 0.5 GW.h in total). As reviewed in the table below Figure 2-3, off-grid diesel generation growth since 2009 at the Wolverine mine has doubled off-grid diesel generation GHG emissions (from 13,827 tonnes/year in 2009 to 27,137 tonnes/year in 2010).

2.2 OVERVIEW OF POTENTIAL YUKON LOADS: 2011-2050

Yukon is currently experiencing a mining resource boom driven by world commodity market demands. As noted in the Preface, mineral exploration expenditures and claims in Yukon have recently climbed to record highs. The 2011 Resource Plan load forecasts explore the potential implications of this record resource activity for future on and off-grid electricity loads in Yukon. These load forecasts were prepared during 2011, at a time of major uncertainties regarding the health and stability of world markets.

Given that the Resource Plan is intended to guide planning and development over the next five years and to be updated every five years, the load forecasts are directed at the near-term time period with extensions over the longer-term 20-year and 40-year time periods in order to help assess longer-term opportunities and challenges.

- Updated load forecasts have been prepared for firm electricity sales (i.e., excludes secondary sales) to non-industrial customers and industrial customers on the new integrated WAF-MD grid, the YECL off-grid communities and off-grid industrial mine sites.
- The methodology for these load forecasts as reviewed in Appendix C is consistent with that used in the 2006 Resource Plan, reflecting available population forecasts, recent trends in non-industrial customer electricity load growth and current electricity forecasts for specific mines as noted (see Appendix C for details by customer class). Grid generation forecasts (hydro and diesel generation) have been prepared based on current and committed generation resources,

[51] As noted in Appendix C, Attachment C-1, Watson Lake generation has a very modest annual growth (0.51%), with 2010 generation at 14.0 GW.h.
[52] As noted in Appendix C, Attachment C-1, Beaver Creek, Destruction Bay and Swift River together have a very modest annual growth in generation (0.13%), with overall 2010 generation at 3.9 GW.h.
[53] As noted in Appendix C, Attachment C-1, Old Crow has a moderate annual growth (1.71%), with 2010 generation at 1.9 GW.h.
[54] Dawson was part of the Large Diesel rate zone and Stewart Crossing was in Small Diesel Rate Zone prior to completion of Mayo Dawson Transmission Project in 2004 and Pelly was Small Diesel Community prior to completion of CSTP Stage 1 in 2008.

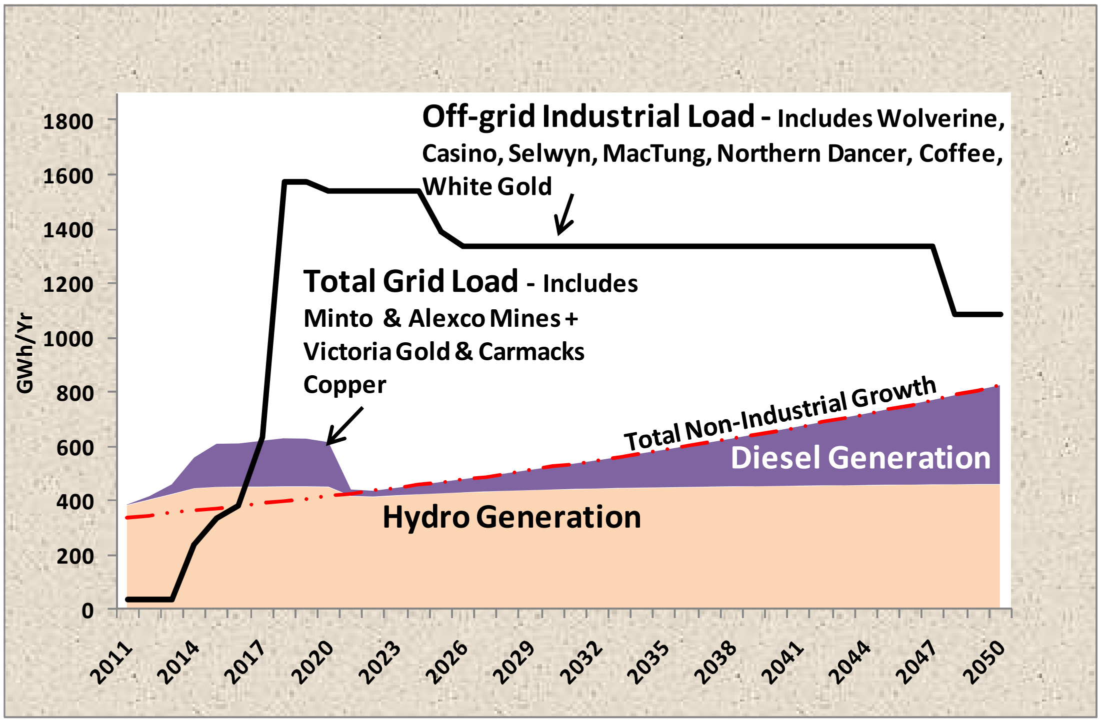
excluding existing wind generation and Yukon Electrical's Fish Lake hydro generation (the impact of these exclusions is noted in Appendix C).

Load forecasts for a 20-year planning period (let alone for longer periods) are subject to considerable uncertainty and risk. In Yukon, unlike typical southern Canada jurisdictions, connection or disconnection of any one mine load can have potentially major impacts on overall grid generation requirements. The pace of non-industrial load growth in Yukon can also be materially impacted by the pace of mine development and the stability of existing mine loads. Faced with the uncertainties inherent in the industrial load forecasts, the forecast approach focuses more on assessing a range of industrial-related scenarios that need to be considered than on detailed investigation of non-industrial residential or general service retail loads.

Figure 2-4 below provides a longer-term overview to 2050 of potential Yukon electricity generation loads, highlighting the overall impact of various off-grid mine loads that are currently being pursued for development in Yukon before 2020 (see Figure 2-5) as well as potential industrial and non-industrial Yukon grid generation loads (including potential new mine loads in YEC's current near-term load scenarios) that are assumed in this initial overview to be met by existing and currently committed hydro and diesel generation.

Figure 2-4 does not include either future diesel generation for the YECL off-grid communities (Figure 2-3 shows this load currently at about 20 GW.h/year, with a trend of only modest growth) or potential implications of climate change considerations (discussed below).

Figure 2-4: Existing System Capability to Supply Potential Grid Load & Potential Off-Grid Mine Loads: 2011-2050



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

	2011*	2015	2020	2025	2030	2035	2040	2045	2050
Grid Load/Hydro Supply Gap**	2	158	163	40	83	138	204	278	364
(Forecast Diesel Generation-GW.h/yr)									
Potential Off-Grid Mines	37	332	1,538	1,390	1,338	1,338	1,338	1,338	1,088
(Forecast Diesel or LNG*** GW.h/yr)									
Total Yukon Diesel or LNG Generation (GWh/yr)	39	490	1,701	1,430	1,421	1,476	1,541	1,616	1,451
Total Potential GHG's (tonnes)	**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

In sum, Figure 2-4 illustrates many of the resource planning challenges to be addressed in the 2011 Resource Plan:

- Focusing on the grid, there is a material increase in potential grid connected industrial loads in the near-term (2013-2021) reflecting potential Victoria Gold (Eagle Gold) and Carmacks Copper mine loads as well as growth in currently connected Minto and Alexco loads; however, as discussed below, this spike in potential grid load growth is not currently forecast to continue beyond about 2021. Forecast grid diesel requirements with such increased load (and no new generation resources) climb to 176 GW.h/year in 2018-19, decline sharply to 22 GW.h in 2022, and then grow thereafter at an annual forecast rate of 2.26% per year (reflecting base case forecast non-industrial load growth prior to any demand side management program), increasing to slightly over 80 GW.h by 2030 (the end of the current 20-year planning period).

- Looking at the off-grid industrial loads, within the 20-year resource planning period and well beyond 2030 material and sustained potential off-grid generation is indicated – and, unlike any past experience in Yukon, the potential off-grid industrial loads effectively dwarf the current projected grid system load potential before 2020. Based on the magnitude and duration of these potential loads, resource planning challenges arise in looking to define what, if any, legacy generation and transmission resource developments could merit serious consideration today for Yukon.
- In total, the potential loads in Figure 2-4 show that, absent solutions that include new renewable or low GHG emitting sources of generation being developed, total Yukon diesel or other non-renewable generation could exceed 490 GW.h by 2015 and 1,700 GW.h by 2020. The table below Figure 2-4 shows the potential resulting dramatic increase in Yukon GHG emissions by as soon as 2015, with a potential increase in GHG emissions from about 27,000 tonnes in 2011 to over 340,000 tonnes in 2015 and over 800,000 tonnes by 2020. While impacts from potential new grid mine loads (primarily Victoria Gold and Carmacks Copper) are currently expected to be for a limited time period (from 2013 through 2021), GHG emission impacts from potential off-grid mines are expected to persist well beyond the 20-year resource planning period.

Currently connected mine loads and new industrial loads that are potentially expected to be connected to the grid over the next few years appear to offer only limited potential justification for developing new capital intensive legacy resources. If all of these potential mine connections and loads materialize, there will be a relatively brief period when industrial generation loads on the grid will increase from 46 GW.h in 2011 to more than 230 GW.h between 2015 and 2018, and then decline to slightly over 195 GW.h in 2020 before dropping sharply (to 14 GW.h in 2021 and zero in 2022).

- It is possible that connected mine loads will continue longer than is currently forecast – or that delays in development of some of the new mine loads could facilitate spreading out of the duration of these grid loads. Sensitivity tests for such possible extensions to 2025 or 2030 are provided in subsequent sections when assessing generation resource options. However, until specific new information is available to confirm the likely occurrence of such possibilities, it would be difficult and risky to commit new resources dependent on these possibilities.

- It is also possible that other new mines will undertake the costs and commitments needed to connect to the grid. There are currently only a limited number of potential mine opportunities located within 50 to 100 km of the 69-138 kV grid (e.g., potentially Rau Gold, Ketza River and Brewery Creek)[55]. Larger potential new off-grid mines such as Casino, Selwyn, Mactung and Northern Dancer[56] are not currently considering connection to the Yukon grid in order to meet load requirements.

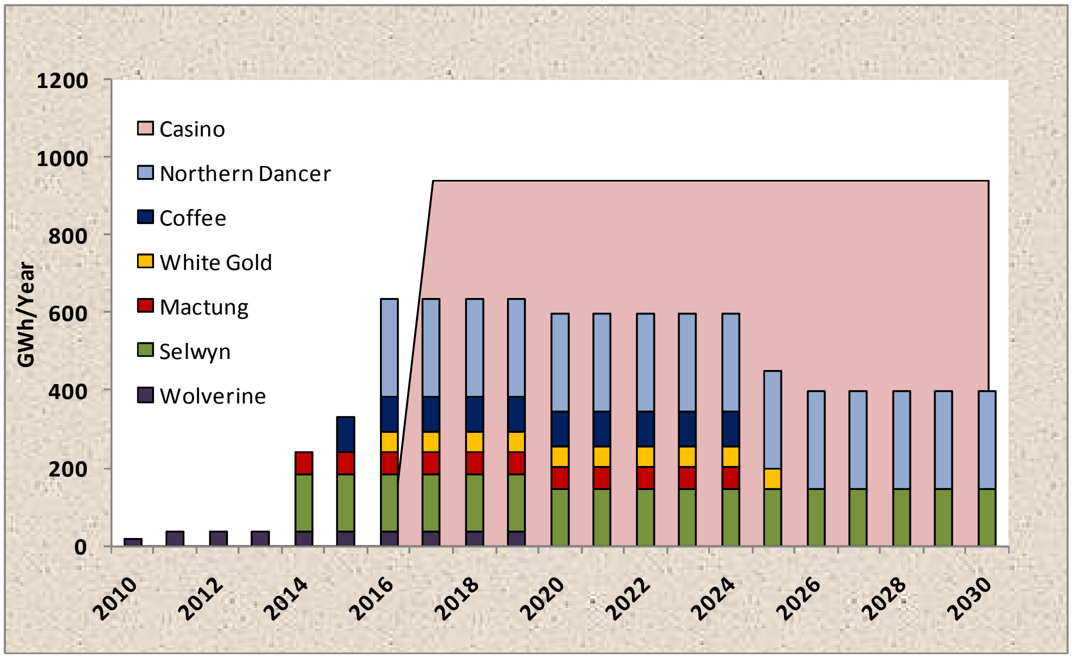
- The possibility also exists that new mine connection loads will be much more limited than assumed in Figure 2-4, due to delays or limitations in the development of specific mines, serious and sustained slumps in world mining commodity demands, or inability to secure the approvals needed for such connections. To the extent that new mines are in fact developed, the GHG emission related generation impacts will remain as a major issue regardless as to whether or not the mine is connected to the grid[57].

[55] As discussed in Appendix B, Attachment B-2, the current industrial maximum utility investment policy requires that industrial customers seeking interconnection pay the full capital costs for any line to connect the mine site with the Yukon grid. Generally, interconnections at distances greater than 50-100 km are considered to be cost prohibitive for potential industrial customers. The limited current information on the prospective mines noted to be within 50-100 km of the 69-138 kV grid suggests requirements for a relatively small scale power load with a relatively short mine life.

[56] The Northern Dancer mine would be located within 100 km to the east of Teslin which is served by 35 kV transmission connected to YEC's 138 kV WAF grid; however, the scale of the Northern Dancer load (i.e., 30- 35 MW) would require upgrade to at least 138 kV for any Yukon grid connection.

[57] Stakeholder comments included in the Charrette Participant's Guidebook indicate a concern on the part of those individuals and entities consulted to consider greenhouse gas targets and reductions and to consequently reduce reliance on diesel generation (and emission) through development of renewable resource projects or through replacing diesel with cleaner burning fuels. Strong public preference for alternative sourced energy is also supported by other Yukon Energy surveys undertaken in 2011.

Figure 2-5: Potential Off-Grid Mine Loads – 2010-2030 (GW.h)



Potenial Off-Grid (GWh):*	2011	2015	2020	2025	2030	2035	2040	2050
Wolverine	37	37	-					
Casino	-	-	941	941	941	941	941	941
Selwyn	-	147	147	147	147	147	147	147
Mactung	-	58	58	-	-	-	-	-
White Gold	-	-	52	52	-	-	-	-
Coffee		90	90					
Northern Dancer			250	250	250	250	250	
Total	37	332	1,538	1,390	1,338	1,338	1,338	1,088

*** Potential mines > 100 km distance from 69-138 kVgrid,from grid, based on current information

Forecast scenario **Industrial GHG Emissions (tonnes)**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
GHGs - Potential Off Grid Mine Loads								
Wolverine	25,900	25,900	-	-	-	-	-	-
Casino**	-	-	331,914	331,914	331,914	331,914	331,914	331,914
Selwyn		102,900	102,900	102,900	102,900	102,900	102,900	102,900
Mactung		40,600	40,600	-	-	-	-	-
Northern Dancer			175,000	175,000	175,000	175,000	175,000	
White Gold			36,400	36,400	-	-	-	-
Coffee		63,000	63,000	-	-	-	-	-
Total Off Grid Mine GHGs	25,900	232,400	749,814	646,214	609,814	609,814	609,814	434,814

****Assumes develop using LNG & combined cycle power generation**

Figure 2-5 provides added detail for 2010-2030 regarding the seven specific potential off-grid mine loads included in Figure 2-4. The table below the figure extends the generation load information to 2050 for each mine, and also provides estimated GHG emissions for each mine.

Off-grid mine developers have emphasized the need for certainty in meeting their energy requirements, i.e., in seeking to secure all relevant commitments needed to proceed, they do not want to "put their fate in other's hands" and need assurance that energy requirements will be met for projected timelines and at competitive costs (based on their own supply option assessments).

In this respect, the developers of the off-grid Casino mine (with a large scale power requirement of 130 MW and 941 GW.h/year potentially sustained over several decades) expect to use LNG (rather than diesel) with combined cycle generation as the preferred energy source[58] for on-site generation in order to reduce costs related to baseload power generation at the mine site to within an 11-15 c/kW.h range (versus the 30+ cents/kW.h range for diesel). Under this approach, Casino would retain flexibility to further reduce operating costs by converting the power generation to natural gas when/if local natural gas becomes available (e.g., power generation costs estimated at <10 c/kW.h with access to Alaska Highway Pipeline Project natural gas). Use of LNG also provides additional complimentary opportunities for Casino (i.e., use of LNG for truck transport).

Yukon Energy is working with Western Copper and Gold (the developers of the Casino mine project) to explore opportunities for joint activities to secure mutual benefit from development of LNG-based generation (as planned currently for Casino) or other new Yukon resource options that might be justified and developed with the Casino project. Access to LNG in Yukon may provide an opportunity for Yukon Energy to replace diesel gensets (required for peaking or baseload use) with dual fuel diesel/gas units that are lower cost to operate when using LNG and that have overall (30%) lower emissions when operated with LNG[59].

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[58] The mine developers (Western Copper and Gold) currently plan to import LNG from new supply facilities currently being planned at Kitimat and/or that could be developed in the Fort Nelson area. See Section 6 for more detailed review of LNG option opportunities.

[59] Environmental impacts of diesel generation include air emissions (e.g., GHG at approximately 700 tonnes per GW.h with normal operation of a new unit generating about 4 kW.h per litre of diesel fuel, and regulated health-related emission effects re: NOx, SO2 and particulates), noise, and potential fuel spills effects (including storage tank leaks). In contrast, LNG or natural gas offers cleaner environmental impacts than with diesel generation, e.g., GHG for simple cycle operation using 8.204 Mcf/MWh at approximately 36% less than diesel fuel (about 451 tonnes GHG emissions per GW.h) and for combined cycle using 6.562 Mcf/MWh are 48% reduction (about 361 tonnes GHG emissions per GW.h); regulated health air emission effects re: NOx, SO_2 and particulates are also typically materially lower than diesel fuel emissions; and there are reduced potential concerns re: fuel spills effects (including storage tank leaks) compared with diesel fuel. Use of combined cycle options (rather than singe cycle) would further reduce fuel requirements and GHG emissions, and could also facilitate use of waste heat to displace fossil fuel heating requirement. By way of example, at the Casino mine scale of operation, operation on LNG with combined cycle at over 50% efficiency results in about 353 tonnes GHG per GW.h or approximately 50% of what would occur with normal diesel generation.

Introduction of LNG into the territory may also enable fuel switching (e.g., for use in vehicles) on a territory wide basis, helping to reduce overall Yukon GHG emissions[60].

It is recognized that any new off-grid load opportunities to develop new legacy resource options for Yukon are each clearly subject to project-specific negotiation and joint planning with each developer to determine if mutually acceptable arrangements and opportunities can be concluded, including appropriate risk management and mitigation measures to protect all other grid-served customers from unacceptable rate-related risks. In the case of the larger off-grid mine projects, initial operation would also likely need to commence using fossil fuels and on-site power generation (as was the case with the Minto Mine connected to the grid in 2008) with any grid connected generation commitments being linked to the completion of new legacy generation and transmission facilities with appropriate third-party contributions towards planning and construction costs as occurred with CSTP[61] and Mayo B; a sufficiently large and stable load extending over 20 or more years would also likely be needed to ensure that the energy generated by new bulk power assets is fully utilized over a reasonable period of years.

Overall, the March 2011 Charrette also recognized the importance in electricity resource planning of addressing climate change considerations in Yukon going forward. Currently in Yukon, utility power generation accounts for only about 3% of GHG emissions, while transportation and building heating account for over 85% of GHG emissions[62]. In order to reduce GHG emissions in Yukon, heating and transport sector fossil fuel use reductions may be sought through fuel switching and electrification.

The following considerations are noted with regard to potential fuel switching and electrification programs:

- Electricity is "clean" when used for heating if generated from a renewable energy source; however, it is generally more efficient to use clean fuels (e.g., biomass) directly in heating

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[60] The calculation of GHG emissions reduction is based on emissions factors provided the National Inventory Report (Environment Canada). Accordingly, the combustion of a litre of diesel fuel a total of 2.7898 kg of CO_2 equivalent [2663g CO_2 + (0.133g x 21)g of CH_4 + (0.40 x 310)g of N_2O]. At an assumed efficiency for a new unit of 4 kW.h per litre of fuel the CO_2 produced per kW.h is 0.6975kg CO_2 equivalent per kW.h or 697.5 tonnes of CO_2 eq. per GW.h (rounded to 700 tonnes for this report). Natural gas combustion would result in emissions factors of 1916g CO_2 per cm (this relies upon emission factors provided for B.C., which are within same range as emissions factors for Alberta; natural gas for Yukon LNG in the near-term would be sourced from Northern BC or Alberta), (0.49 x 21)g of CH_4 and (0.049 x 310)g of N_2O and would result in total of 1.941 kg of CO_2 eq. per cm (or 0.05493 kg per cf). For simple cycle operation at efficiency of 8.204 Mcf/MW.h, GHG emissions equal 451 tonnes per GW.h; for combined cycle at efficiency of 6.562 Mcf/MW.h, GHG emissions equal 361 tonnes per GW.h.

[61] CSTP would not have proceeded absent YEC securing a material contribution towards the Carmacks Stewart Main Line from Minto mine through a Power Purchase Agreement.

[62] John Streiker.2011 "Climate Change" presentation to YEC Energy Charrette (transport 64% of Yukon GHG emissions, heat 22%, industry 9%, and electricity generation 3%, other 2%).

applications rather than to use such fuels first to generate electricity that is then used for heating[63].

- Opportunities for combined heat and power (i.e., related to biomass or gas co-generation facility) will depend upon locating the plant where use can be made of waste heat. A biomass plant located at Haines Junction or the Minto area, for example, would reduce transportation costs related to fuel supply, but provide no major opportunity to use waste heat. In contrast, a waste, biomass or natural gas thermal plant located in the Whitehorse may create an opportunity to use some of the waste heat. Reflecting these considerations, Yukon Energy is committed to examining combined cycle units for all new thermal generation facilities in Whitehorse and is also carrying out feasibility work to determine the business case for district heating in Whitehorse.
- Electricity for vehicle transportation is a potential new use that in future could greatly increase electricity loads; other potential new electricity uses to help reduce GHG emissions may occur in many different areas, including displacing use of natural gas in pipeline compression stations (potentially relevant in Yukon if new pipelines are developed).
- Electrification of pipeline compressor stations[64] and/or any other major long-term electrification in non-industrial sector loads[65] are potential additional future electricity generation loads (these potential loads are not included in Figure 2-4 or Figure 2-5). Pipeline compressor stations in Yukon (if developed) are expected to use natural gas[66]; however, this development plan will serve to increase overall GHGs in Yukon. Available information suggests that each of the six compressor stations in Yukon for an Alaska Highway Pipeline (AHPL) Project would have 33 MW demand and about 245 GW.h of annual energy, with an assumed in service date of 2020-21 and

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[63] See for example Fernando Preto "Bioenergy" presentation to YEC Energy Charette (direct wood heating in home at 75% energy conversion efficiency as compared to 25% energy conversion efficiency for a large biomass electricity generation plant).

[64] In the event that the Alaska Highway Pipeline is developed (potentially by 2021), there may be an opportunity to electrify some of the project's six compressor stations in close proximity to the grid along the Alaska Highway, thereby securing large, stable long-term loads that would reduce GHG and other emissions if supplied by new hydro or geothermal legacy generation facilities (each of the six planned compressor stations would have an approximate 33 MW load requiring about 245 GW.h/year of electric energy over a project life of 25 years).

[65] Electrification opportunities that might significantly increase electricity loads include electric vehicles (impacts by the early 2020's are likely to be minimal) and electrification of pipeline compressor stations (as discussed below, any such increase would likely be a material jump in loads). Electrification scenarios reviewed by BC Hydro suggest that electricity retail sales could be as much as 30% to 50% higher in 2050 than would otherwise be the case based on current trends after DSM-related reductions, with most of this electrification-related growth occurring after 2030. Potential electrification trends in North America, however, create considerable uncertainty and risk regarding potential material increases in longer-term grid generation loads after the next 10 to 20 years.

[66] Current information provided by TransCanada indicates that each station will be self sufficient and electricity will be generated using natural gas from the pipeline.

expected project life of 25 years[67]. Assuming use of natural gas, this would in effect potentially result in 109,466 tonnes of new GHG emissions annually per compressor station (and there would be several such stations in Yukon). In addition to reducing GHG emissions, electrification of at least some of the AHPL compressor stations could also potentially provide the type of large, stable long-term load required for development of low cost legacy assets such as large hydro or geothermal.

- BC Hydro in recent years has begun to examine potential future load growth increases due to fuel switching and electrification. Its latest base forecasts include electric vehicles at only modest levels in the next decade, and expanding to less than 3% of all sales by Fiscal 2031 (approximate 16% penetration for light duty vehicles). BC Hydro's analysis includes electrification scenarios wherein retail sales increase by up to 50% by 2050 relative to baseload forecasts, including 70% electrification of light duty fleet vehicles and 42% for the heavy duty fleet vehicles (approximately 75% of the overall 50% retail sales percentage increase occurs after the 20-year time period relevant to the 2011 Resource Plan)[68].

In the event that the electrification scenarios materialize as reviewed in BC Hydro's recent analysis, such electrification trends in North America would also likely result in material increases in longer-term Yukon electricity demand, starting perhaps before 2020 but concentrated primarily after 2030, due to electrification in the residential, commercial, industrial and transportation sectors. Overall, as suggested in BC Hydro's forecasts, electrification may result in long-term growth in electricity demand that more than offsets reductions secured through DSM. To avoid adverse impacts on regional GHG emission reduction goals, such increases to Yukon electricity demand would need to be satisfied with low-carbon electricity resources. Marbek is currently undertaking an end use survey that will provide a more detailed information and analysis related to types of uses that contribute to the system peak (including electric heating) – results may be incorporated into the Resource Plan once finalized.

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[67] Proponents of the Alaska Pipeline Project provided a project schedule in September 2011 community meetings in Alaska (See TransCanada web site on Alaska Pipeline Project - presentation September 21, 2011 to the Alaska Annual Oil & Gas Conference) indicating first gas in 2020 and full gas in 2021, assuming an October 2012 FERC filing and project sanction before mid-2015. It is expected that six compressor stations would be required in Yukon, plus a gas heater station.

[68] Greenhouse Gas Reduction Scenarios for the Western Interconnection (2010-2050), related Addendum; Energy and Environmental Economics, Inc. (prepared for BC Hydro 2011 Integrated Resource Plan), January 2011. GHG reduction scenarios: 30% reduction in energy related GHG emissions by 2050 relative to 2008; and 80% reduction in energy related GHG emissions by 2050 relative to 2008.

Electrification loads noted above (i.e., fuel switching for pipeline compressor stations, transportation and heating) are not included in 2011 Resource Plan load forecasts; however, it is recognized that climate change policies may modify electricity load growth over the longer-term (i.e., starting in the 2020s and extending over the following decades). Potential electrification impacts that may materially increase longer-term Yukon retail (non-industrial) generation loads are identified as a major longer-term forecast uncertainty in the 2011 Resource Plan. On this basis, potential electrification trends in British Columbia and other North American jurisdictions merit ongoing monitoring and review.

2.3 2011 RESOURCE PLAN GRID LOAD SCENARIOS: 2011-2030

In order to provide reliable service, utility planning requires that each grid system have installed generation adequate to supply the required peak capacity (MW) and annual energy (kW.h) as forecast over the planning period.

- **Capacity planning** focuses on the highest or peak megawatt (MW) generation capability (capacity) required on each system during each year, including sufficient reserve capability (based on the system's capacity planning criteria) to address generation and transmission unit breakdowns.

- **Energy planning** focuses on the number of kilowatt hours (kW.h) of electricity that are required to be generated over the course of a season or year on each system.

Looking at capacity planning, the primary grid system planning consideration in Yukon is the system capacity capability during the peak winter months when hydro capacity is constrained by low water flows (especially at Whitehorse) and overall grid loads are highest (see Figure 1-1). The existing diesel infrastructure as reviewed in Appendix A is utilized today primarily as reserve capacity to meet peak or short-term grid emergency needs.

Looking at energy planning, the primary grid system planning consideration today in Yukon is to provide affordable and environmentally responsible service. Existing diesel generation capacity on the grid currently ensures that Yukon has ample capability to supply reliable energy when hydro capability is fully utilized (including during winter months when hydro capability is constrained), i.e., at 90% capacity factor for the diesel units, the existing 44.2 MW of grid diesel capacity could potentially provide almost 350 GW.h per year of electricity. However, reliance upon diesel generation to supply energy requirements in excess of hydro capability has high cost and emission impacts - accordingly, utility planning examines forecast diesel energy requirements in order to identify and assess technically feasible and appropriate options to displace diesel energy generation.

The 2011 Resource Plan examines forecast electricity generation on the new integrated grid as well as off-grid mine sites that might be connected to the grid[69]. New resource supply options are assessed in the context of forecast capacity and energy generation load requirements over the near-term and longer-term based on forecast firm electricity sales to non-industrial customers and industrial customers, and excluding secondary sales[70]. As reviewed below, the existing generation and transmission system can reliably supply energy and capacity by resorting to default diesel. Priority attention is first directed to forecast grid energy requirements, reflecting the extent to which increased diesel energy requirements (versus capacity requirements) can adversely impact Yukon Energy costs and GHG emissions.

2.3.1 Forecast Grid Energy Requirements 2011-2030

New resource opportunities in Yukon are typically defined by forecast grid diesel energy generation to be displaced by less costly and/or lower GHG emission options. The 2011 Resource Plan load forecasts focus on diesel displacement opportunities as one of the major challenges related to Yukon being an isolated grid, and the reality that diesel generation to date has remained the default option in Yukon to meet new capacity and energy load requirements not otherwise supplied by existing hydro generation.

Forecast baseload diesel generation reflects combined non-industrial and industrial grid generation requirements, net of the forecast capability of existing and currently committed grid hydro generation to supply these loads[71]. Hydro generation forecasts reflect average water year conditions, as well as the forecast loads (i.e., as reviewed in Appendix D, hydro generation for existing facilities will increase to some extent as annual loads increase, and is also sensitive to the seasonal distribution of forecast loads).

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[69] Appendix C provides details on the load forecast scenarios for Yukon industrial and non-industrial loads (on-grid and off-grid); Appendix D reviews capacity and energy capability of the grid generation facilities.

[70] To simplify the assessment of resource requirements and options, grid generation forecasts also exclude existing wind generation and YECL's Fish Lake hydro generation.

[71] The forecasts as prepared in early 2011 assumed load forecasts for 2012 and 2013 based on the long term trends as noted, and that the Mayo Lake Storage Enhancement Project (i.e., to reduce the licenced bottom storage at Mayo Lake by 1 metre) would be in service starting in 2012. Filing of the YESAB project proposal for the Mayo Lake Storage Enhancement Project is now not expected until later in 2011, and implementation of this project is now not expected prior to winter 2013/2014 at the earliest (more likely winter 2014/2015) – as a result, long term average hydro generation forecasts in the 2011 Resource Plan (which assume that this project is in place) are overstated, and diesel generation forecasts are understated, by about 4 GW.h per year for the period until the Mayo Lake Storage Enhancement Project comes into service. The 2011 Resource Plan also is not amended for any new Yukon Energy Business Plan forecasts developed during 2011 for the years 2012 and 2013.

Over the 2011 Resource Plan period non-industrial growth in Yukon is forecast to occur primarily on the grid and at a higher rate than in the previous Resource Plan.

- The 2011 Resource Plan assumes non-industrial growth[72] of 2.26% per year together with sensitivities (reviewed in detail in Appendix C and Attachment C-1). Non-industrial annual growth on WAF in the 2006 Resource Plan was projected at 1.85%, or 0.41 percentage points below the forecast medium growth rate of 2.26% in the 2011 Resource Plan. This forecast non-industrial growth is based on the methods developed for the 2006 Resource Plan (described in detail in Appendix C, Attachment C-1). The medium growth rate is based on a combination of Whitehorse population growth and Whitehorse residential Use per Customer (UPC)[73] (from 2001 to 2010) and WAF medium-high growth per year (reflecting YEC's nine year average growth rate with native YECL wholesales[74]).
- The non-industrial growth forecast recognizes:
  - Residential and commercial development continues to be evidenced in Whitehorse as well as other areas along the 2001 to 2010 trend line[75].
  - Ongoing Faro reclamation operation general sales loads expected to continue to reflect 2009/2010 experience (load projected for 2011 at 4.8 GW.h per year); based on available information, it is assumed that current water pumping and treatment as reflected in the 2010 loads will extend indefinitely.

[72] Non-industrial includes residential, general service and lighting customer classes.

[73] Trends in average electricity use per customer throughout different Canadian utilities have reflected a variety of factors, including increased use of electronics, more efficient appliances, improved building insulation, and various other changes. Moderating impacts on customer use in many jurisdictions also reflect demand side management (DSM) programs implemented by the utilities. The modest growth rates in use per customer assumed in the Resource Plan Update forecast would presumably be reduced by any similar DSM program implementation in Yukon.

[74] Excluding Fish Lake impacts and impact of Pelly Crossing connection in 2008 and including all Faro dewatering loads after closure of the Faro mine in 1998.

[75] There is some sensitivity of firm wholesales to secondary wholesales, which varied considerably over this period and were suspended in September 2010 due to low water conditions. Firm wholesales include losses (approximating 7%) on secondary wholesales. In fall 2010, when secondary wholesales were suspended, the majority of secondary sales customers converted to firm service (impact approximates 0.7 GW.h in 2010 for partial year, reflecting ongoing annual impact of 1.5 GW.h).

The 2011 Resource Plan defines three near-term grid load scenarios to assess potential resource options (forecast hydro and diesel generation requirements by year for each option is provided in Table 2-2):

- **Base Case** – The Base Case includes the non-industrial load forecast (annual growth of 2.26%) plus forecast loads for currently connected mines (Minto and Alexco[76]). Diesel generation is forecast to increase from 1.5 GW.h/year in 2011 to 24 GW.h in 2015 and 42 GW.h in 2019; based on the best available information at this time, currently connected mine loads are assumed to shut down after 2020 and as a result grid diesel generation is forecast to decline to 16 GW.h in 2021; thereafter baseload diesel generation to supply only non-industrial loads increases to 40 GW.h in 2025 and almost 83 GW.h in 2030.
- **Scenario A** – Scenario A includes the Base Case plus connection of the Victoria Gold mine (i.e., the Eagle Gold Project at Dublin Gulch property) by 2014[77]. Diesel generation is much higher during the period when Victoria Gold is assumed to operate (until the end of 2020), increasing from 92 GW.h in 2014 to 124 GW.h in 2019[78]. Thereafter, based on the best available information today, the Scenario A load forecast assumes that all of the mines assumed to be connected to the grid are no longer operating and that no other mines would be seeking connection to the grid. Under these assumed load assumptions, forecast diesel after 2020 is the same as the Base Case.

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[76] Alexco's existing mine is located at the Bellekeno mine site in the Keno region. Alexco is currently also operating a mill in the Keno region and plans to develop other mines in the vicinity to use this mill in the near-term.

[77] Load forecasts as prepared in early 2011 assumed, based on the then available information, Victoria Gold connection in late 2013 with the forecast loads shown here. The likely timing for such connection is currently under review with Victoria Gold, but is not now expected prior to the first quarter of 2014 (the 2011 Resource Plan load forecasts continue to assume connection in late 2013). The Victoria Gold power load forecasts are also currently under review: somewhat higher annual energy and capacity levels are being examined, with reduced levels required during peak winter months and higher levels during the balance of the year such that the overall net result would be little if any overall change in forecast annual grid diesel energy generation requirements (no changes have been made to the 2011 Resource Plan load forecasts for Victoria Gold to reflect such possible adjustments).

[78] On July 22, 2011 the Eagle Gold Project Proposal (Victoria Gold) completed the adequacy review stage of the YESAB assessment process and commenced the project screening stage. The Project Proposal posted on the YESAB website notes a 7.3 year active mining phase, with mining of the Phase 1 starter pit scheduled to commence mid-year 2013. The Project proposal assumes grid interconnection through a new 45 km and 69 kV transmission line. The 1.5 MW demand required during construction will be supplied through on site diesel generators. The average seasonal forecast for the operations phase is estimated to be 11 MW supplied by grid power with three emergency diesel generation sets available in the event of a power failure. Power demand for closure and reclamation phase has not yet been determined. For the purposes of the environmental assessment Eagle Gold has identified power supply as a valued ecosystem component.

- **Scenario B** – Scenario B includes the Base Case plus connection of the Victoria Gold mine by 2014, the Carmacks Copper mine[79] in late 2014 and Whitehorse Copper Tailings mine in spring 2013[80]. Further increases in diesel generation are forecast, e.g., 112 GW.h in 2014, 176 GW.h in 2018 and 2019. By 2022 current planning scenario assumptions based on the best available current information are that all connected mine loads are assumed to be shut down and forecast diesel would return to Base Case levels. Delay in developing and connecting any of these mines would result in corresponding extensions of the mine loads beyond 2021.

The three different grid loads described above demonstrate the impact of two different mine connection scenarios over the period to 2021. Resource Plan forecasts have been prepared based on the best available load information regarding potential connected mine loads and timing, and are subject to change in the future in response to new information. See Table 2-1 and Figure 2-6 for a summary of available information on potential mine and pipeline loads.

[79]The Carmacks Copper mine, which is being developed by Copper North Mining Corp. (formerly Western Copper Corporation), completed its YESAB review process is September 2008 (when the Yukon Government issued a Decision Documents accepting the YESAB recommendation that the project proceed). The subsequent Yukon Water Board hearing in early 2010 did not result in a water licence for the project. Subsequent to a court ruling on the YWB decision, Western Copper announced in March 2011 that it has initiated engineering studies to determine whether certain aspects of the project could be modified to improve the project's reclamation process and thus satisfy the main concern of the YWB, and is working with regulatory authorities in Yukon to establish the next steps towards getting the project fully licensed. Timing for development and connection of this mine remains very uncertain.

[80] Based on information available in early 2011. By fall of 2011, delays in timing for this project appear likely, but no changes have been made to the 2011 Resource Plan load forecasts for Scenario B. The load for this mine would be focused entirely in the non-winter season.

Table 2-1: Yukon Industrial Development Opportunities

Project	Proponent	Distance To Grid (km)	Peak Demand (MW)	Annual Energy (GW.h)	Project Life (yrs)	Assumed Earliest In-Service Date
Alaska Highway Pipeline Project (33 MW/station)						
Six compressor stations	Trans Canada Corp.	Varies	33x6	246x6	25	2020-21
One heater station	Trans Canada Corp.	NA	33	246	25	2020-21
Potential Mine Developments > 20 MW						
Casino Property	Western Copper and Gold	115 km	132	940.8	20-30+	2018-19
Northern Dancer	Largo Resources	65 km	30-35	200-300	29-30	late 2016 - 2017
Selwyn Project	Selwyn Resources Ltd	170	20	147	80	2014
11 to 20 MW						
Eagle Gold (Dublin Gulch)	Victoria Gold Corp.	45	13	95	7.3	2013 (late)
Coffee Gold Property	Kaminak Gold Corp	N/A	14-15	90	10+	2015
1 to 10 MW						
Carmacks Copper	Copper North Mining Corp.	12	10	52	6.5	2015
Whitehorse Copper Tailings	Eagle Industrial Minerals	0	2	8.7	6	2013
MacTung	North American Tungsten	250	6-8	58	11+	2015
Ketza River	Yukon-Nevada Gold Corp.	85	2.5	2	6	2012(Dec)
Rau Gold	ATAC Resources Ltd	88 km	N/A	N/A	10	N/A
Brewery Creek	Golden Predator	N/A	N/A	N/A	N/A	N/A
Tagish Lake Gold Property	New Pacific Metals	N/A	4	N/A	N/A	N/A
White Gold	Kinross Gold Corp.	160	5-10	30-60	10	2017
Wolverine	Yukon Zinc Corp.	273	5.1	37	9.5	2010-11

Sources and notes: See Appendix C, Attachment C2.

It is recognized that a wide range of possible variations in loads may occur over the planning period to 2030, including delays in connection of specific mines, extensions in the life of any connected loads and expansions or contractions in connected loads. Rather than attempt to define a certain number of different load scenarios, Sections 4 to 6 test sensitivities of various resource options' cost effectiveness to different potential extensions of mine loads beyond 2020, e.g., diesel displacement assumed with Scenario A or Scenario B peak loads related to connected mines (e.g., in 2019) is extended to 2025 and also to 2030 where relevant to test a resource option's sensitivity to currently projected mine loads.

Figure 2-6: Yukon Exploration Projects 2010

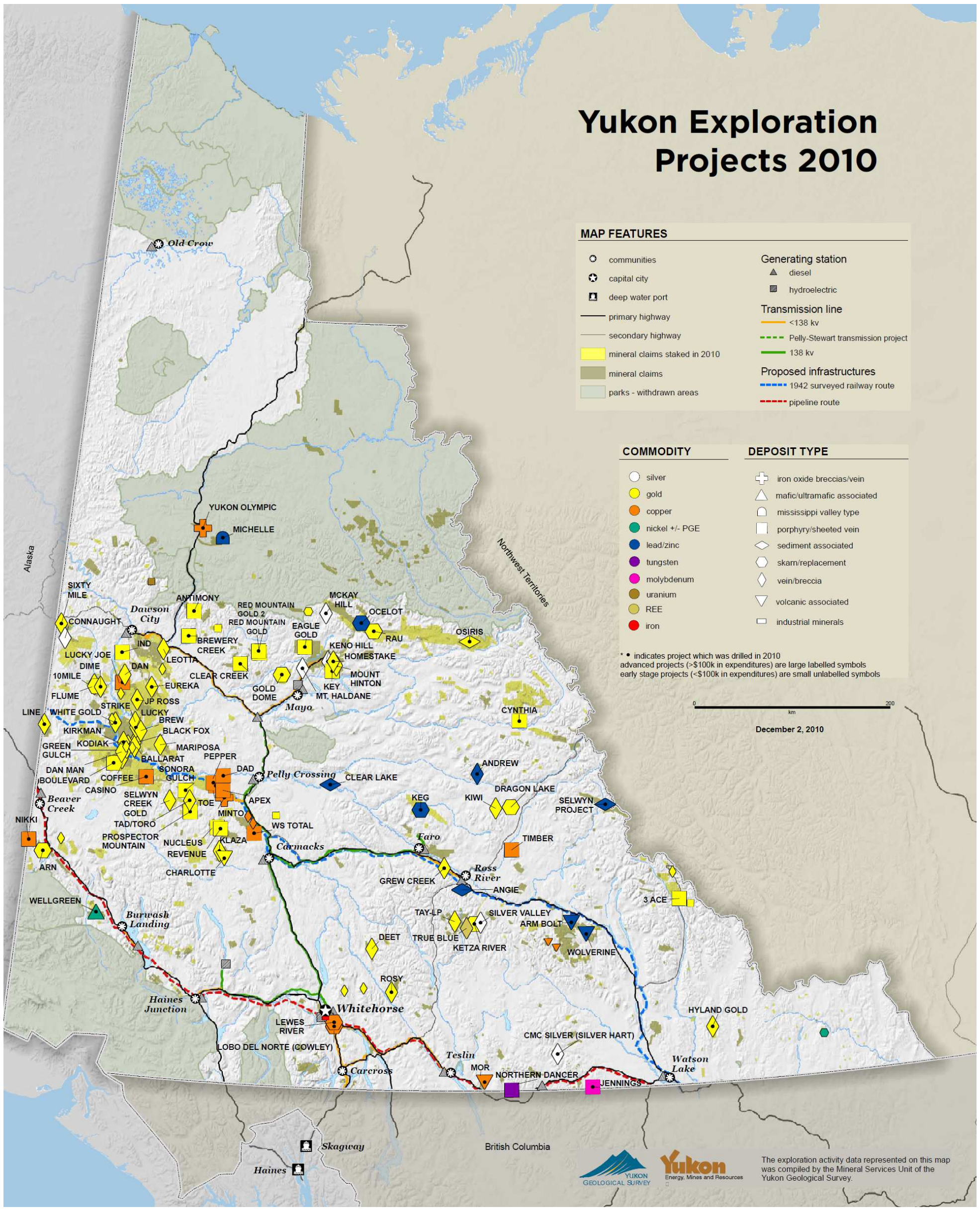
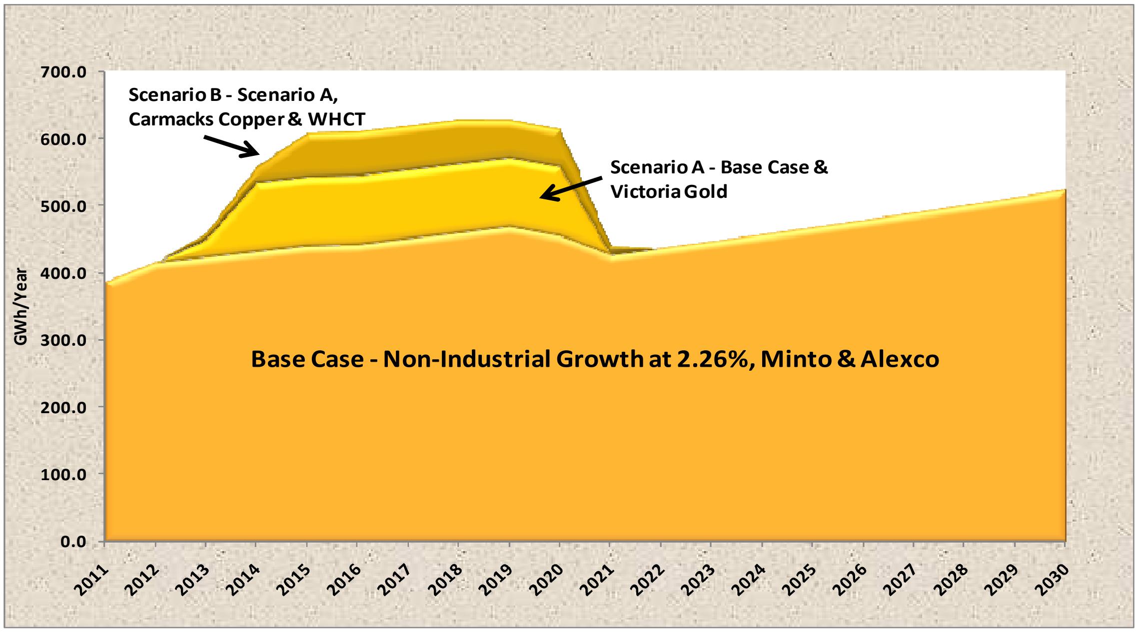


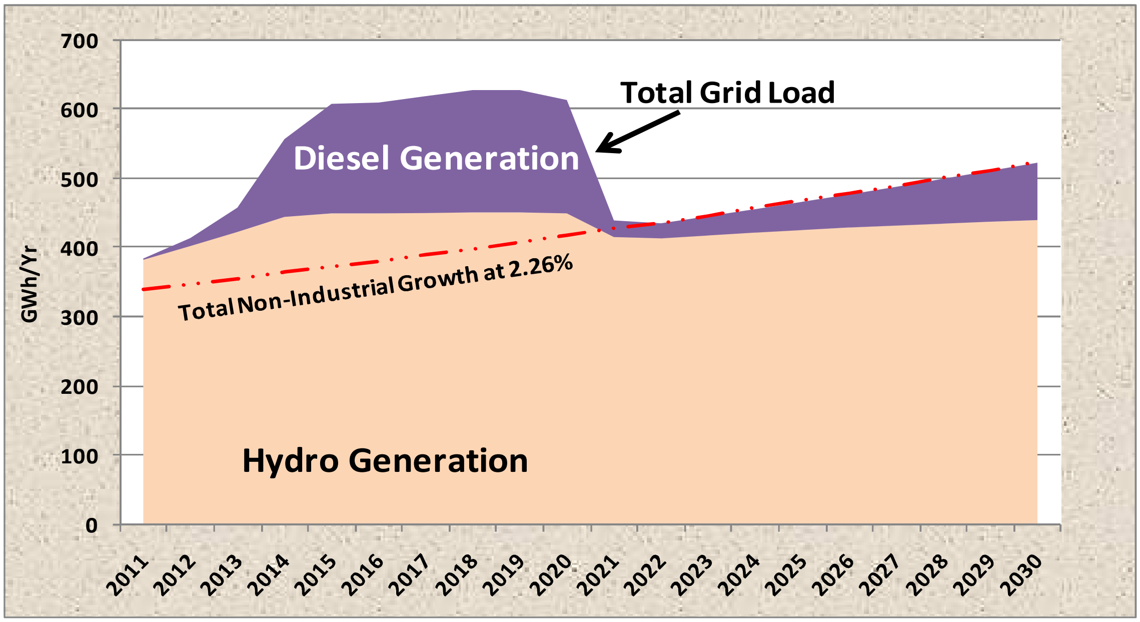
Figure 2-7 below provides forecast grid loads under the three grid load scenarios described above.

Figure 2-7: Forecast Grid Loads: Base Case, Scenario A and Scenario B



		2011	2015	2020	2025	2030
Non-Industrial Growth at 2.26%		339.3	371.9	417.0	467.5	523.9
Base Case						
	Alexco	12.8	21.7	15.0	0	0
	Minto	33.7	46.7	23.3	0	0
	Total GWh	**385.8**	**440.3**	**455.4**	**467.5**	**523.9**
Scenario A (Base Case & Victoria Gold)						
	Victoria Gold	0	102.6	102.6	0	0
	Total GWh	**385.8**	**542.9**	**558.0**	**467.5**	**523.9**
Scenario B (Scenario A & CC and WHCT)						
	Carmacks Copper	0	56.5	56.5	0	0
	Whitehorse Copper Tailings	0	9.4	0.0	0	0
	Total GWh	**385.8**	**608.8**	**614.4**	**467.5**	**523.9**

Figure 2-8: Scenario B Forecast Grid load/Hydro Supply Gap: 2011-2030



	2011	2015	2020	2025	2030
Total Grid Load	386	609	614	467	524
Total Hydro & Wind Generation	384	404	424	446	451
Diesel Requirement No DSM/SSE	**2**	**158**	**163**	**40**	**83**

Figure 2-8 above provides the total available hydro generation under Scenario B grid loads noted in Figure 2-7 (i.e., Scenario A and Carmacks Copper and Whitehorse Copper Tailings). Notably, under both Scenario A and Scenario B forecast grid loads there is increased hydro available to displace grid diesel generation[81]. Available hydro and diesel generation under each load scenario is provided in Table 2-2 below.

[81] Hydro generation forecasts are based on YEC's power benefits model which reflects long-term average net generation capability to displace diesel for each year at the forecast power demand – this net hydro generation increases as power demand increases, assuming WAF-MD grid connection by mid 2011, Mayo B in service (with the Mayo Lake Storage Enhancement Project) by start of 2012, and the current licence and Fish Act Authorization rules for Aishihik operation. Filing of the YESAB project proposal for the Mayo Lake Enhanced Storage Project is now not expected until later 2012, and implementation of this project is now not expected prior to winter 2013/2014 at the earliest (more likely winter 2014/2015) – as a result, long term average hydro generation forecasts in the 2011 Resource Plan (which assume that the Mayo Lake Enhanced Storage Project is in place) are overstated, and diesel generation forecasts are understated, by about 4 GW.h per year for the period until the Mayo Lake Enhanced Storage Project comes into service. The power benefits model analysis for the 2011 Resource Plan has also not been adjusted to reflect specific seasonal load shapes for specific mines – based on information as of the fall of 2011 (including potential changes to the Victoria Gold load forecasts), refinement of the power benefits model analysis to reflect specific seasonal load shapes for specific mines would not result in material changes to the diesel generation forecasts currently included in the 2011 Resource Plan.

Table 2-2: Forecast Hydro Generation and Diesel Generation under Forecast Grid Loads: Base Case, Scenario A and Scenario B

Forecast Years	Base case		Scenario A		Scenario B	
	Hydro	Diesel	Hydro	Diesel	Hydro	Diesel
2011	383.3	1.5	383.3	1.5	383.3	1.5
2012	403.1	11.5	403.1	11.5	403.1	11.5
2013	407.5	15.1	419.6	29.0	423.2	34.8
2014	411.7	19.2	441.8	91.7	445.0	112.1
2015	415.6	23.7	443.0	98.9	449.7	158.1
2016	416.5	24.8	443.3	100.5	449.9	159.9
2017	420.2	29.9	444.5	108.2	450.5	168.1
2018	423.6	35.5	445.5	116.2	451.1	176.5
2019	426.8	41.5	446.5	124.4	451.1	176.2
2020	421.8	32.5	445.0	112.0	450.1	163.3
2021	409.1	16.6	409.1	16.6	415.8	24.0
2022	413.9	21.6	413.9	21.6	413.9	21.6
2023	418.4	27.3	418.4	27.3	418.4	27.3
2024	422.4	33.5	422.4	33.5	422.4	33.5
2025	426.2	40.3	426.2	40.3	426.2	40.3
2026	429.5	47.7	429.5	47.7	429.5	47.7
2027	432.6	55.7	432.6	55.7	432.6	55.7
2028	435.4	64.2	435.4	64.2	435.4	64.2
2029	437.8	73.2	437.8	73.2	437.8	73.2
2030	440.1	82.8	440.1	82.8	440.1	82.8

2.3.2 Forecast Grid Capacity Requirements: 2011-2030

Yukon Energy included an extensive review of grid capacity planning criteria in the 2006 Resource Plan. This review resulted in new criteria being adopted for Yukon Capacity Planning purposes on the WAF and MD grids.

- **Loss of Load Expectation (LOLE)**[82] - In 2006, the system-wide capacity planning criteria for WAF and MD provided that each integrated system would be planned not to exceed a Loss of Load Expectation of 2 hours/year[83].

[82] This is a probability based measure to evaluate the maximum loads that a grid system can safely carry by identifying the potential interruption of service for any customer (forecast of the average number of system outages per year). The LOLE criteria also recognize the role of transmission reliability, where relevant. The LOLE function is an average that does not indicate how long any particular outage will last, or the potential severity of consequences for customers – thus a further emergency standard (N-1 criteria) was also adopted.

- **Emergency (or "N-1") Standard**[84] - This criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation resource. This approved capacity planning criteria looks only at non-industrial grid loads and currently provides for WAF sufficient winter peak capacity reserve to accommodate loss of the Aishihik transmission connection to Whitehorse[85]. It is recognized today that Aishihik hydro plant capability is being increased to 37 MW (reflecting addition of the 3rd turbine in 2011); however, loss of the Whitehorse transmission connection to the Aishihik hydro plant is considered the single largest contingency on the grid system and, therefore, no Aishihik generation capability is included as reliable capacity for purposes of the N-1 test.

The January 2007 YUB Report to Commissioner in Executive Council on the 2006 Resource Plan generally recommended to the Yukon Government adoption of the capacity planning criteria as proposed by Yukon Energy; however, the YUB's report recommended that major industrial loads not be included in the LOLE calculation[86]. An approach that excludes industrials from the LOLE calculation would mean that normal firm rates charged to these customers (as compared to some materially lower rate more akin to secondary power) can likely only be justified if these customers are assured firm power supplies based on inclusion of all such customers in LOLE calculations[87]. On this basis Yukon Energy's position is that industrial loads must continue to be included in the LOLE calculation. The YUB has suggested that any such issues be brought forward in subsequent applications[88].

[83] The WAF system has substantial hydro generation availability that is directly affected by certain transmission; the WAF system also has been trending to an increasing probability of longer outages as it expands (particularly with expansion of residential and commercial loads and major reductions in industrial load). Yukon Energy therefore in 2005 incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages.

[84] Under this emergency standard, each integrated system (WAF and MD) is planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as the N-1).

[85] In 2006 it was noted that for WAF the single most critical system component is the Aishihik transmission line and the largest single potential loss of supply at that time would be 30 MW (the installed Aishihik capacity) due to loss of transmission line from Aishihik to Whitehorse.

[86] See YUB Report to Commissioner in Executive Council re YEC 20-Year Resource Plan – Jan 2007 at page 10. The YUB's recommendation was "in order to ensure that no new generating capacity is added for the purposes of ensuring reliable supply to major industrial customers and to ensure consistency with the N-1 criterion, major industrial loads should not be included in the LOLE calculation." The YUB re-iterated this recommendation in Order 2007-5 at page 27.

[87] See for example response YUB-YEC-1-5 in the Part 3 hearing regarding Mayo B.

[88] See page 16 of YUB Report re Part 3 Review of CSTP.

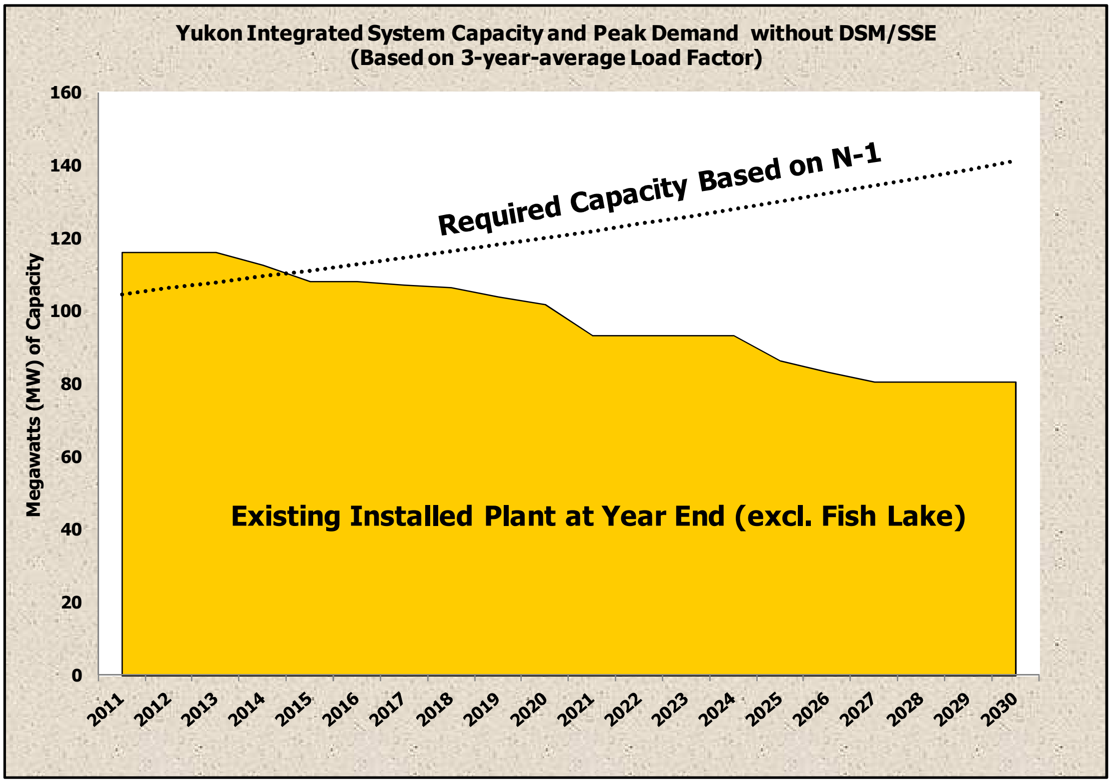
Updated Assessment of N-1 Standard for 2011 Resource Plan

Table 2-3 below sets out the current grid generating units and rating (MW capability assumed for winter peak period) by location and utility, comparing capacity rating by unit today with what was provided in the 2006 Resource Plan. Table 2-3 also includes current assumed retirement dates by unit. In summary, grid capacity shortfalls under the N-1 capacity planning criteria are materially impacted by potential diesel plant retirements prior to 2030 (Table 2-2 indicates a total 35.6 MW reduction in diesel capacity over the planning period that includes all current YEC reliable diesel plant)[89].

Figure 2-9 below shows the N-1 grid capacity planning MW surplus (shortfall) for 2011-2030 assuming diesel units planned to retire are not life-extended or replaced.

[89]In the 2006 Resource Plan, YEC proposed Life Extension plans for all existing Mirrlees units at Whitehorse. Since that time YEC has proceeded with refurbishment of the Mirrlees unit at Faro and one Mirrlees unit at Whitehorse (these units are now planned to retire in 2021). These refurbishments of 9 MW were completed at an average cost of approximately $0.467 million/MW, excluding the WD3 generator rebuild. YEC currently plans to retire the two remaining Mirrlees units, reflecting significant increases experienced in off engine equipment requirements as engines approach end of life (e.g., cooling system, HVAC systems, electrical systems, air start systems) and changes in availability of parts and service support. The WD 2 unit will be used as spare parts for WD3 and FD1.

Figure 2-9: Grid Capacity Capability & N-1 Capacity Requirements – 2011-2030 (MW)



	2011	2015	2020	2025	2030
Existing Plant (MW)	**116.2**	**108.2**	**101.9**	**86.4**	**80.6**
Requirement without DSM/SSE (MW)					
N-1 Requirement	104.7	111.1	120.0	129.9	141.0
Surplus (shortfall) (MW)	11.6	-2.8	-18.0	-43.5	-60.4

Figure 2-9 indicates grid capacity shortfalls emerging in 2015, and expanding thereafter, under the N-1 capacity planning criteria and assuming diesel units planned to retire are not life-extended or replaced. This assessment is based only on forecast non-industrial loads on the integrated grid and is therefore not affected by load forecast variations related to different potential industrial loads.

1 **Table 2-3: Current Integrated Grid Generating Complement**

Unit	2006 Resource Plan Rating (MW)	2011 Resource Plan Rating (MW)	Expected Retirement Date
Whitehorse Hydro (winter for all units)	24.00	24.00	NA
Whitehorse diesel #1 (Mirrlees)	3.00	3.50	2014
Whitehorse diesel #2 (Mirrlees)	4.20	4.50	2015
Whitehorse diesel #3 (Mirrlees)	4.20	4.50	2021
Whitehorse diesel #4 (EMD)	2.50	2.25	2025
Whitehorse diesel #5 (EMD)	2.50	2.25	2025
Whitehorse diesel #6 (EMD)	2.70	2.50	2025
Whitehorse diesel #7 (Caterpillar)	3.30	3.00	2026
Faro Diesel #1 (Mirrlees)	0.00	4.00	2021
Faro Diesel #3 (Caterpillar)	1.00	0.85	2019
Faro Diesel #5 (Caterpillar)	1.30	1.20	2020
Faro Diesel #7 (Caterpillar)	3.00	2.80	2027
Aishihik #1	15.00	15.00	NA
Aishihik #2	15.00	15.00	NA
Aishihik #3	0.00	7.00	NA
Carmack's Diesel (YECL)	1.30	1.60	
Pelly Crossing (YECL)	0.00	0.98	
Haines Junction diesel (YECL)	1.30	1.75	
Teslin diesel (YECL)	1.30	1.50	
Ross River diesel (YECL)	1.00	1.00	
Fish Lake hydro (2 units - YECL, winter capacity)	0.40	0.40	
Total WAF	87.00	99.58	
Dawson diesel #1 (Caterpillar)	0.80	0.72	2018
Dawson diesel #2 (Caterpillar)	1.00	0.92	2017
Dawson diesel #3 (Caterpillar)	1.00	0.92	2020
Dawson diesel #4 (Caterpillar)	0.70	0.00	
Dawson diesel #5 (Caterpillar)	1.50	1.40	2031
Mayo diesel #1 (Caterpillar)	1.00	0.85	2019
Mayo diesel #2(Caterpillar)	1.00	0.85	2019
Mayo hydro (winter all units)	5.40	11.00	NA
Stewart Crossing diesel (YECL)	0.00	0.40	
Total MD	12.40	17.06	
Total Integrated System -Winter Capacity (incl. Fish Lake)	**99.40**	**116.64**	
Grid Winter Capacity after N-1 event (excl. Fish Lake)	**67.70**	**77.49**	

2

Updated Assessment of LOLE Criteria for 2011 Resource Plan

Under the LOLE capacity planning criteria in the 2006 Resource Plan (see Appendix D), additional grid capacity would be required in the near-term under the Base Case, Scenario A and Scenario B in response to forecast grid mine loads in excess of about 13 MW (see Appendix C, Attachment C2, Table C2-2) from late 2013 until approximately 2020[90]. By the 2012 timeframe, industrial loads are projected to increase to the level where LOLE criterion as set out in the 2006 Resource Plan would begin to become relevant for capacity planning purposes; however, based on forecast load requirements over the resource planning period, and to the extent that industrial loads become relevant for capacity planning, the LOLE criterion would become relevant over a relatively brief period (with industrial loads currently forecast to shutdown by 2021).

For the 2011 Resource Plan, Yukon Energy has reviewed the adequacy of the capacity planning criteria given the material changes on the integrated grid system since the last review (i.e., integration of MD and WAF grids through completion of CSTP and Mayo Hydro Enhancement project)[91]. Preliminary results from the LOLE review suggest that the earlier model assessments of LOLE for WAF may still be usefully applied for the integrated grid, subject to the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced so as to provide no line constraint.

Estimated required added capacity under Scenario A and B loads is assessed (see Figure 2-10) based on the assumption that grid industrial peak winter load requirements in excess of 13 MW add directly to the required grid capacity[92] and that diesel units planned to retire are not life-extended or replaced.

On this basis, the following added capacity requirements (relative to the N-1 assessment) are assumed when the LOLE capacity planning criteria is applied with forecast industrial loads (see Figure 2-10 for the resulting capacity shortfall forecasts)[93].

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[90]In its recent Part 3 Report on Mayo B, the YUB noted that YEC intended to produce an LOLE model of its integrated system and to conduct a study of future generating capacity requirements utilizing this model for future review as part of the five-year update of its 20-Year Resource Plan (see page 17 of YUB Report re: Part 3 review of Mayo B).

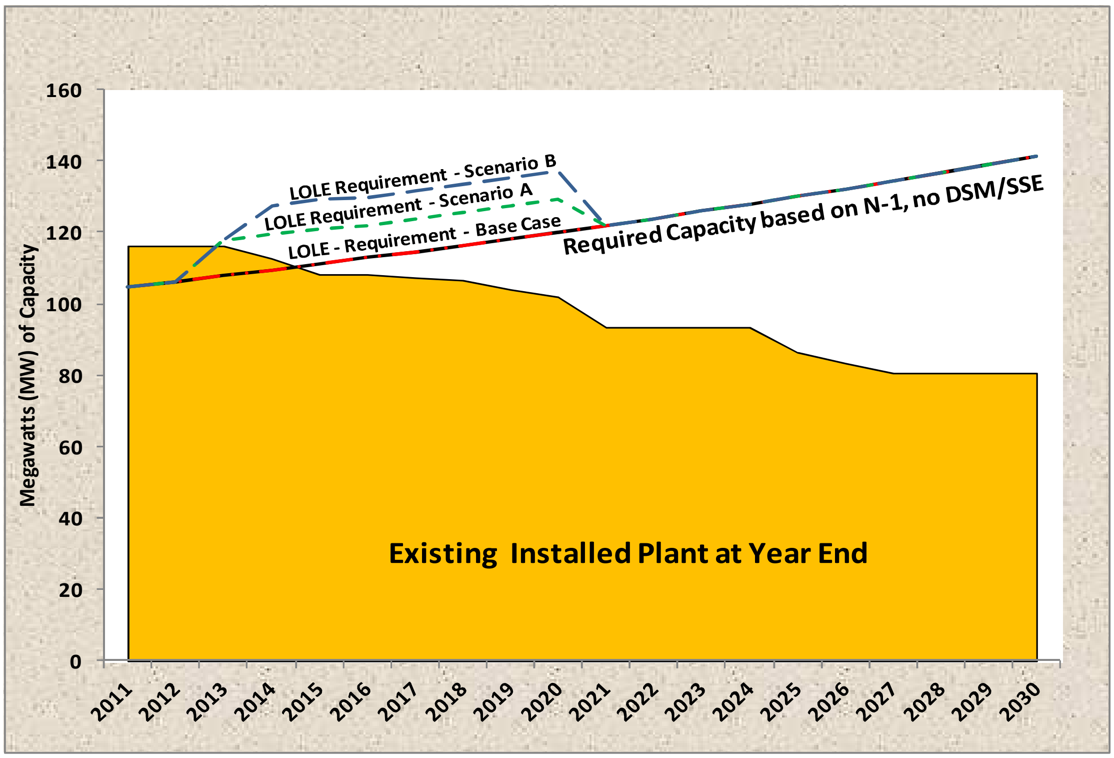
its recent Part 3 Report on Mayo B, the YUB noted that YEC intended to produce an LOLE model of its integrated system and to conduct a study of future generating capacity requirements utilizing this model for future review as part of the five-year update of its 20-Year Resource Plan (see page 17 of YUB Report re: Part 3 review of Mayo B).

[92] Estimated based on LOLE assessments update with Victoria Gold load distribution.

[93] Victoria Gold capacity during winter is assumed at 13 MW based on forecasts available in early 2011. This is subject to ongoing review (more recent information suggests that the winter peak requirement may be materially reduced).

- **Base Case:** No added capacity needed under LOLE over N-1. The capacity shortfall in 2015 is approximately 3 MW, increasing to 18.0 MW in 2020.
- **Scenario A:** Added capacity of 10 MW needed in 2015 through 2020 and no impacts after 2020. The capacity shortfall in 2015 is approximately 13 MW, increasing to 27 MW in 2020.
- **Scenario B:** Added capacity of 18 MW needed in 2015 through 2020 and no impacts after 2020. The capacity shortfall in 2015 is approximately 21 MW, increasing to 35 MW in 2020.

Figure 2-10: Grid Capacity Capability Requirements – 2011-2030 (MW)



	2011	2015	2020	2025	2030
Existing Plant (MW)	**116.2**	**108.2**	**101.9**	**86.4**	**80.6**
Requirement without DSM/SSE (MW)					
N-1 Requirement	104.7	111.1	120.0	129.9	141.0
Surplus (shortfall) (MW)	11.6	-2.8	-18.0	-43.5	-60.4
LOLE - Base Case	104.7	111.1	120.0	129.9	141.0
Surplus (shortfall)	11.6	-2.8	-18.0	-43.5	-60.4
LOLE - Scenario A	104.7	121.1	129.1	129.9	141.0
Surplus (shortfall)	11.6	-12.8	-27.1	-43.5	-60.4
LOLE - Scenario B	104.7	129.1	137.1	129.9	141.0
Surplus (shortfall)	11.6	-20.8	-35.1	-43.5	-60.4

2.4 CAPACITY & ENERGY RELATED CHALLENGES FOR EXISTING GRID UNDER FORECAST LOADS

Challenge to Displace Diesel Energy Generation

Based on the 2011 Resource Plan grid load forecasts, the major near-term challenge for the next five years in particular is to reduce costs and GHG emissions by displacing diesel energy generation that would otherwise be required between 2014 and 2021. Assuming that the current Yukon mining boom is sustained, the very large longer-term challenge highlighted by the 2011 Resource Plan load forecasts is to secure long-term grid load growth beyond 2021 sufficient to achieve low cost and low GHG emission legacy energy supply project development.

These conclusions reflect the following summary of capacity and energy related challenges for the existing integrated grid under the forecast loads during the 20-year planning period:

- **Capacity:**
    - In the next 5 to 10 years, the grid capacity challenge relates mostly to replacement on retirement of between 8 MW and 23 MW of diesel generation assets, and providing between 3 MW and 24 MW of additional reliable peak winter capacity for added industrial loads, as required, under the LOLE criteria.
    - Within the 20 year planning period, replacement of all (35.6 MW) YEC diesel capacity is expected to be required plus a further 25 MW of new capacity by 2030.
    - Under the Scenario A or B load forecasts, industrial loads within the next 5 years are forecast to accelerate the need for new capacity that will otherwise be required later within the 20-year planning period.
- **Energy:**
    - The grid energy challenge throughout the 20-year planning period is to reduce costs and GHG emissions by displacing diesel energy generation that would otherwise be required.
    - Existing and committed grid generation resources can fully supply the near-term forecast annual and seasonal energy loads during the 20-year planning period[94].

[94] Assumes replacement of diesel generation assets on retirement and added diesel capacity as required under the capacity planning criteria (N-1 and LOLE); applicable even with all potential new grid connected mine loads forecast prior to 2021 under Scenarios A or B.

  - With the diminished surplus hydro generation available today, continued reliance on the existing grid system (i.e. prior to considering new non-diesel resource options) to address load growth will require increased reliance on costly diesel generation to meet energy loads. By 2015, grid diesel generation is forecast to increase from 2 GW.h/year in 2011 to 23.7 GW.h under the Base Case (no new mine connections), to 98.9 GW.h under Scenario A loads, and to 158.1 GW.h under Scenario B loads. After 2021, when no mine loads are currently forecast to be connected, grid diesel generation is forecast to grow from 21.6 GW.h in 2022 to 82.8 GW.h in 2030.

The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, means that backup capacity is required to supplement available hydro in circumstances of low water or drought. The substantial diesel capacity on the grid provides this required backup capability.

However, diesel energy generation as projected under the forecast loads (particularly under load Scenarios A or B) defines a significant challenge for the existing grid during the planning period – a challenge not faced since the Faro mine closed in 1998 and a challenge made much more difficult today by higher diesel fuel prices plus policy concerns about GHG emissions from diesel fuel generation.

As will be reviewed in Sections 3 and 4, this challenge can be addressed in part through programs to reduce loads (Demand Side Management) and improve the efficiency of the existing grid (Supply Side Enhancement). However, the Scenario A and B load forecasts in particular define sharp jumps in diesel energy generation potentially as soon as 2014-2015. Aside from the challenge inherent in developing new and less costly supply in Yukon within such a short time period, the Scenario A and B load forecasts also show sharp reductions in diesel energy generation potentially as soon as by 2021. This means that any new supply must also be very flexible (as well as less costly than diesel) in order to accommodate such major potential load swings within such a short time period.

Longer-term legacy supply resource development during the planning period will require sustained ability to displace sufficient forecast diesel generation on the grid. The 2011 Resource Plan load forecasts show that the opportunity to secure such loads will likely be dependent upon the extent to which the current Yukon mining boom is sustained and can provide the foundation for long-term grid load levels sufficient to achieve legacy energy supply project development.

- Looking beyond the near-term, the 2011 Resource Plan grid load forecasts show steady growth in diesel generation requirements after 2021; however, by 2030 these requirements are still expected to remain below the 2014 Scenario A forecast diesel generation unless connected mine loads are sustained.

- At the same time, off-grid industrial load forecasts show the potential for dramatic growth if the current Yukon mining boom is sustained. This includes the potential development within the next 10 years of three major new mines (i.e., Casino, Selwyn and Northern Dancer), each with annual energy requirements ranging from 100 to 941 GW.h. Each of these mine loads is expected to continue for 20 years of operation (or longer).

Challenge to Displace Seasonal Diesel Requirements

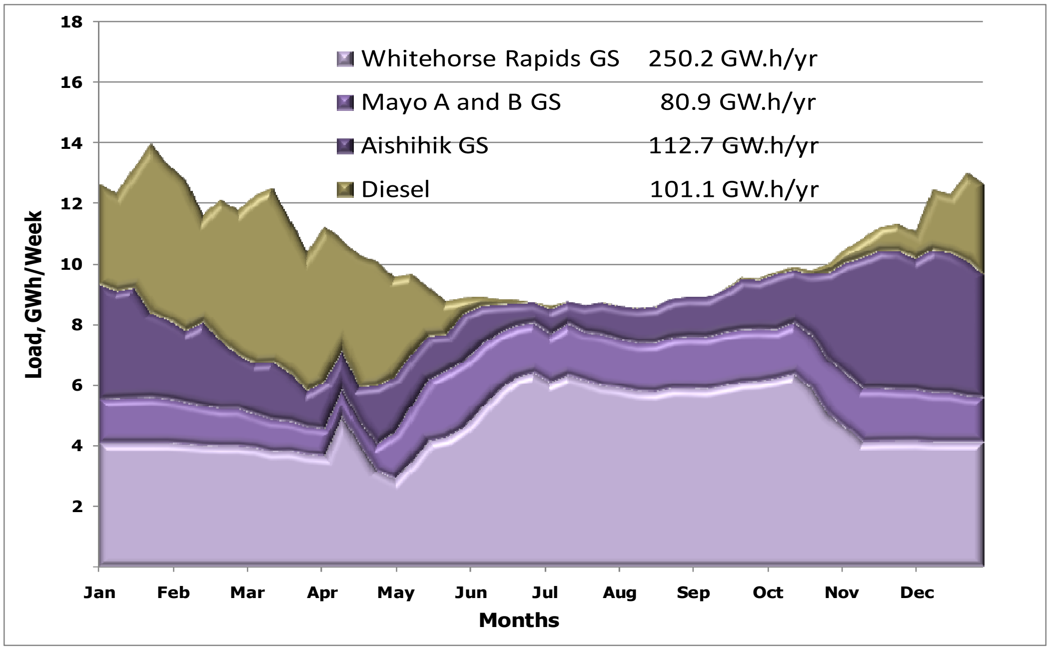
Forecast diesel requirements for the Yukon grid in any year are concentrated in the winter/spring seasons. The challenges related to this reality reflect the following distinctive factors affecting the Yukon grid (also see Figure 1-1):

- Seasonal grid loads (which peak in winter and are lowest in summer);
- Current hydro generation supply (which tends towards surplus in summer, is constrained in winter, and is also highly variable from year-to-year); and
- The isolated nature of the Yukon grid which prevents any export sale of surplus summer/fall renewable generation or import of non-Yukon generation.

Figure 2-11 demonstrates the extent to which grid diesel generation is concentrated in winter-spring months under mean water flow[95] with an annual grid load of 545 GW.h (reflects the approximate Scenario A load with Victoria Gold in 2015-2016). Under this load, 69% of diesel generation occurs in four winter months (December to March), and only 2% occurs in the five summer/fall months (June to October).

[95] Average of all water years of record [1981-2008] and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years are used for the final averaging (this deletes cases where starting or ending volumes can distort results). In total, 364 cases are examined 28 water years and 13 load years).

Figure 2-11: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) at 545 GW.h/year 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	
Diesel Generation	59.9	17.2	9.1	1.9	3.2	9.8	101.1
	59%	*17%*	*9%*	*2%*	*3%*	*10%*	*100%*
Hydro Generation	100.5	25.3	37.1	199.0	41.3	40.6	443.9
	23%	*6%*	*8%*	*45%*	*9%*	*9%*	*100%*
Total Generation	160.4	42.5	46.2	201.0	44.5	50.4	545.0
	29%	*8%*	*8%*	*37%*	*8%*	*9%*	*100%*

Concentration of diesel generation outside the summer-fall period remains a key feature of the Yukon grid under a wide range of load and water flow conditions, as demonstrated by the following examples:

- Under a 610 GW.h/year "high" load scenario (Scenario B) for 2015-16 and in an average water year, over 95% of the direct diesel displacement opportunities occur in the seven month period from November to May (i.e., less than 5% of direct diesel displacement opportunities occur in the five summer/fall months (June to October)).
- Under a 610 GW.h/year "high" load scenario and the lowest water year at this load (1996), over 90% of the average diesel displacement opportunities in that water year still occur in the seven

month period from November to May (i.e., diesel direct displacement opportunities in summer/fall remain minimal at these loads even in the lowest water year))[96].

In response to the seasonal diesel challenge, non-diesel resource options for the Yukon grid that concentrate generation in winter/spring months will clearly be better able to directly displace diesel generation than resource options that are concentrated in summer/fall months. Resource options that provide increased generation during summer/fall (e.g., wind or a biomass thermal plant requiring year-round operation) will in effect displace hydro generation[97]. However, indirect diesel displacement benefits will occur from displacing hydro generation during summer/fall to the extent that enhanced hydro storage is facilitated during summer/fall that allows increased hydro generation during winter/spring.

Figure 2-12 provides an illustrative example of the projected impact a 21 MW wind project would have on seasonal and annual grid generation (mean water flow capability) at an annual grid load of 545 GW.h. The wind project is assumed to provide 55.8 GW.h of new generation over the year with significantly higher generation in winter than during summer[98].

- About 62% of the wind generation (34.6 GW.h) is able to directly displace diesel generation, primarily in winter/spring months – the balance of the wind generation (38% or 21.2 GW.h) displaces hydro generation, primarily in the summer/fall months.
- However, slightly over two-thirds (69%) of the displaced hydro is able to be stored in this case – and used to displace diesel generation during winter/spring months.
- As a result, the wind project on average displaces 49.2 GW.h of diesel generation, with 70% of this displacement occurring directly and the balance (30%) through incremental hydro generation from use of incremental stored water resulting from the wind generation.
- The balance of the wind generation (6.6 GW.h) displaces hydro generation that is spilled and lost.

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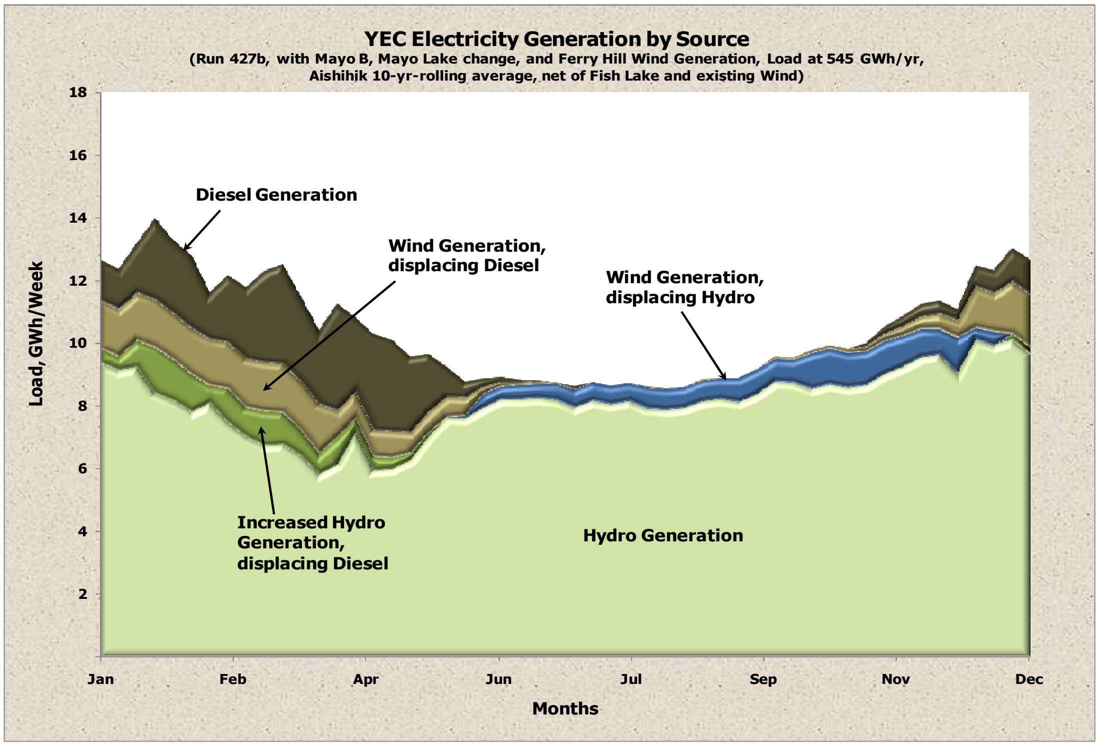
[96] See Figure D-6B in Appendix D.
[97] The concept of wind or wood biomass thermal operation "displacing" generation from existing hydro resources assumes that the wind or wood biomass operation is not suspended at such times as hydro generation cannot be used, i.e., water is spilled rather than used to run the generators. For the purpose of highlighting the challenges related to the existing hydro grid, this concept is retained in this analysis. However, where feasible, YEC would not in practice allow existing hydro generation to be displaced by other more costly sources of generation.
[98] The assumed wind generation approximates 1.5 GW.h/week during winter months versus less than half this level during summer.

Figure 2-12: 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 545 GW.h/year Grid Load (Scenario A 2015-16 load)



Grid Generation at 545 GW/h load* (GW.	Without Wind Project	With 21 MW Wind Project	Change
Grid Load	545.0	545.0	
Grid Generation			
Hydro*	443.9	437.3	(6.6)
Diesel	101.1	51.9	(49.2)
Wind*	-	55.8	55.8
Total	545.0	545.0	

Breakdown of Wind Generation Impacts (GW.h/yr)	
Directly Displacing Diesel	34.6
Directly Displacing Hydro	
Stored Hydro Displacing Diesel	14.6
Spilled Hydro (not required)**	6.6
Total Wind Project Generation	55.8

* 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

The impacts of new renewable resource on existing hydro facility generation will vary widely depending on the assumed grid loads and the assumed seasonal distribution of the new renewable generation. For example, at roughly the same annual load as assumed in Figure 2-12 (542.9 GW.h before DSM/SSE) and with assumed demand side management and supply side enhancement (DSM/SSE) as reviewed in Section 4 (reducing grid load to 526.5 GW.h), stored hydro would account for a lower percentage (56%) of hydro displaced by this same 21 MW wind generation.

Thermal waste-to-energy (Municipal Solid Waste or MSW) or wood biomass thermal projects, with assumed steady levels of generation throughout the year[99], will also displace hydro generation during summer months and thereby result in widely varying incremental stored hydro capability to displace diesel generation during winter/spring months, depending on the grid load as well as the scale of the thermal generation project. The following examples are noted at grid loads approximating 545 GW.h/year:

- Small waste-to-energy projects (1.4 to 2.2 MW) generating between 10.8 and 17.1 GW.h/year will utilize 81 to 83% of this generation to displace diesel, either directly or through incremental stored hydro generation. Slightly over 60% of hydro generation displaced by these projects would be used as incremental stored hydro generation at this assumed load.

- With a 15 MW wood biomass project and 545 GW.h/year load, about 37% of the hydro displaced by the biomass generation is re-used as incremental stored hydro generation (this re-use percentage falls to 27% if DSM/SSE are assumed as in Sections 4 and 5 and the grid load falls to 526.5 GW.h).

- In contrast, with a 25 MW wood biomass project at 545 GW.h/year load only about 13% of the hydro displaced by the biomass generation is re-used as incremental stored hydro generation (this re-use percentage falls to 5% if DSM/SSE are assumed as in Sections 4 and 5 and the grid load falls to 526.5 GW.h).

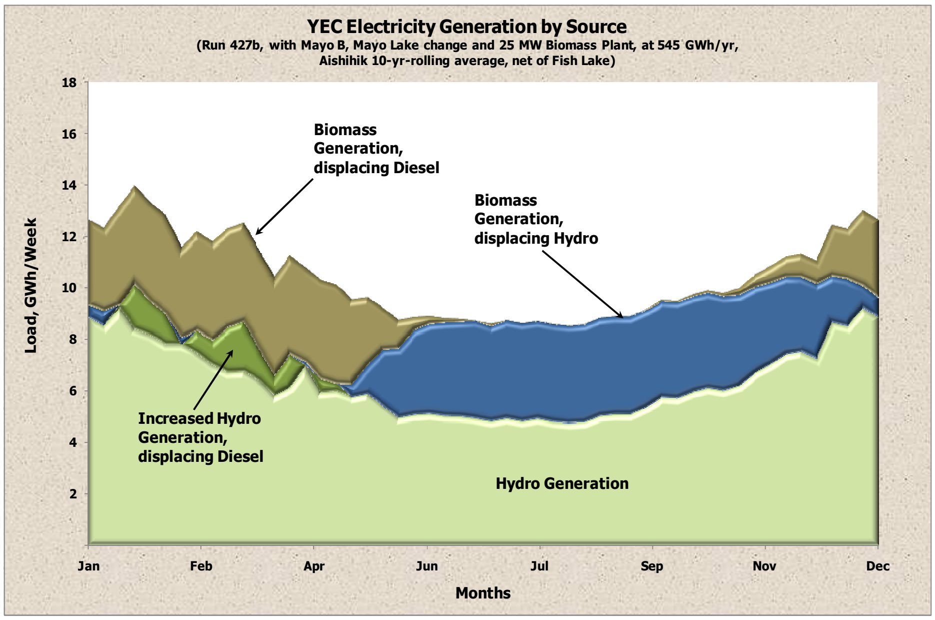
To demonstrate the differences discussed above, Figure 2-13 shows the grid generation by week at the 545 GW.h load with a 25 MW wood biomass project generating 197 GW.h/year. This level of renewable generation on the Yukon grid at the 545 GW.h grid load succeeds in displacing forecast diesel generation - however, on average the level of displaced available hydro that is spilled (95.9 GW.h/year) under the assumed biomass plant operation is almost as large as the diesel displaced (101.1 GW.h/year), and only about 51% of the wood biomass generation is used to displace diesel generation.

In effect, the above analysis underlines the overriding need for any inflexible generation supply source (such as assumed in the above examples) to be scaled to the extent feasible to match the diesel generation to be displaced. Developing new generation that cannot displace diesel generation would be

[99] Unlike wind, the assumed inflexibility of operation for these specific renewable thermal generation reflects assumed economic factors rather than technology requirements. If required, waste or wood biomass generation plants could be shut down for a season or any other specific time period – the relatively high cost of such shut downs, however, would be related to the high capital cost per MW for these options (other aggravating factors might also be related to seasonal supply realities).

wasteful – a factor which is demonstrated, for example, when explaining why long-term large hydro resource developments in Yukon (which offer local renewable supply with minimal GHG emissions) would not be economically feasible without first securing long-term diesel displacement loads to at least match the new hydro generation to be developed. The same principles that apply at an annual load level also apply at the seasonal load level, subject to the ability to facilitate enhanced hydro storage for use during the winter season[100].

Figure 2-13: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) with 25 MW Wood Biomass Project Displacing Diesel and Displacing Hydro at 545 GW.h/year Grid Load (Scenario A 2015-16 load)



Grid Generation at 545 GW/h load* (GW.	Without Biomass Project	With 25 MW Biomass Project	Change
Grid Load	545.0	545.0	
Grid Generation			
Hydro*	443.9	348.0	(95.9)
Diesel	101.1	-	(101.1)
Biomass	-	197.0	197.0
Total	545.0	545.0	

Breakdown of Biomass Generation Impacts (GW.h/yr)	
Directly Displacing Diesel	87.0
Directly Displacing Hydro	
Stored Hydro Displacing Diesel	14.1
Spilled Hydro (not Required)**	95.9
Total Biomass Project Generation	197.0

* Existing Wind and Fish Lake generation not included.

Total Displaced Diesel = 87.0 + 14.1 = 101.1 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

100 The underlying economic feasibility issues noted here are not resolved by resort to secondary sales (interruptible sales) of the surplus hydro. The basic premise of secondary sales is that, at most, very limited investment is made to facilitate such sales, and that such sales are incidental to the project's primary objectives (see response to YUB-YEC-1-44, YEC Mayo B Application for an Energy Project Certificate). On a seasonal basis, secondary sales opportunities in Yukon are also weakest in summer (i.e., the season when diesel generation displacement opportunities are minimal). In summary, while secondary sales would continue to be promoted during periods of hydro surplus in order to reduce overall costs charged to firm service customers, such secondary sales cannot provide a sound economic rationale for planned developments that create surplus hydro on the grid.

Challenge to Displace Diesel Generation with Widely Varying Annual Hydro Generation

Forecast diesel generation at any specific annual grid load is highly variable by year, as well as by season within the year, due to widely varying annual hydro generation. This annual variability creates added flexibility requirements for any new resource developed to displace grid diesel generation.

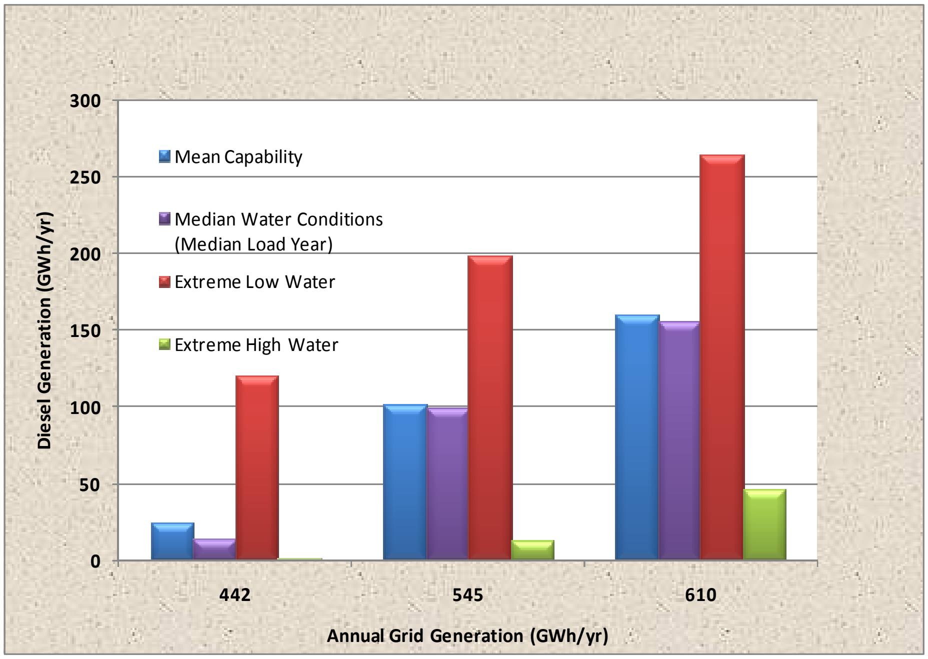
Annual average diesel energy generation on the grid as shown by week in Figure 2-11 reflects averages of widely varying annual water flow conditions. With annual loads at a 545 GW.h annual average diesel generation is projected at 101.1 GW.h/year in Figure 2-11. This average however, includes diesel generation ranging from 13.0 GW.h/year under extreme high water conditions to 198.8 GW.h under extreme low water conditions.

As shown in Figure 2-14, similar variability in annual water conditions is shown at lower (442 GW.h/year) and higher (610 GW.h/year) grid loads, reflecting the approximate range of grid loads in 2015-16 under low (Base Case) and high (Scenario B) 2011 Resource Plan forecasts[101].

This annual variability in hydro generation is a key feature of the Yukon grid affecting the diesel displacement impact to be expected from any new renewable resource. The isolated nature of the Yukon grid prevents any export sale of surplus renewable generation during summer months or during high water years. In effect, when water is available for hydro generation, YEC faces the reality that this water must either be used or lost (spilled) unless it can be stored. Seasonal water storage exists at Aishihik Lake and (to a much more limited extent) at Mayo Lake – Aishihik Lake can also provide limited annual storage.

[101] See Section 4 of Appendix D, and specifically Table D-2 and Figures D-5 to D-7. "Extreme or Median Load Year" is one year out of the 364 cases examined (28 water years and 13 load years). "Averaged Load Years" are the 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).

Figure 2-14: YEC Annual Grid Diesel Generation Variability at Different Grid Loads (GW.h/yr)



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

Based on Yukon's grid conditions, it is desirable to balance the available hydro generation with flexible thermal generation (such as diesel) which has low capital cost to provide capacity and can also be operated on an "as needed" basis. As shown, the hydro generation variability in any year accordingly results in high variability in forecast annual diesel generation:

- Annual diesel generation for any specific load scenario is below average in many (perhaps most) years (e.g., under the 545 GW.h/year "mid" load scenario), diesel generation is less than the average 101 GW.h in 15 of the 28 water years, and less than 86 GW.h in 10 of the 28 water years. This variability highlights one of the challenges facing renewable resource options intended to displace diesel generation on the grid (i.e., reduced generation requirements in many years may undermine the cost effectiveness of a new renewable resource).

- Annual hydro variability also creates the need to rely on greater-than-average diesel generation in drought years. For example, diesel generation capacity required under extreme low water years would approximate 119.7 GW.h at the 442 GW.h/year at the Base Case load in 2015-16, about 198.8 GW.h at the 545 GW.h/year Scenario A load in 2015-16, and about 263.8 GW.h at a 610 Scenario B load in 2015-16 – these requirements will be moderated in practice to the extent that water storage is able to be facilitated by non-hydro generation during summer months[102].

Summary Challenge for Diesel Displacement Resource Options

In summary, non-diesel resource options will be more effective in displacing diesel generation to the extent that they can be focused in the priority diesel generation periods (winter/spring) and flexible to address annual hydro variability. 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).

For example, flexible thermal generation non-diesel resource options (e.g., natural gas/LNG combustion turbines) which can be shut down as required when hydro generation can supply all of the load will tend to operate at low (40-55% range) annual average capacity factors based on the summer/fall hydro capability on the grid. In contrast, flexible thermal generation options also intended to displace average water year diesel generation will require peak winter generation capacities in excess of the average year requirements in order to displace diesel requirements during extreme low water years.

In contrast, inflexible resource options (e.g., wind) that cannot be shut down as required when hydro generation can supply all of the load will result in varying levels of generation (e.g., during summer/fall seasons and during higher water years) that cannot currently be used to displace diesel on the Yukon grid. As demonstrated above, similar unused generation will occur for thermal generation options (e.g, wood or waste biomass generation) which are assumed to operate at high annual capacity factors in order to secure high utilization of the capital cost resources. The degree of such unused generation will be very sensitive to the overall scale of the resource option (e.g., the wasted generation will typically be much greater for a 25 MW facility than for a 2 MW facility).

In order to address these Yukon-specific challenges, assessment of the cost effectiveness of new non-diesel resource supply options in the 2011 Resource Plan is based on costs per kW.h of actual diesel generation displaced or “net generation” (considering annual generation impacts and seasonal variability)

[102] Under the lowest water years peak diesel generation capacities required may be higher, e.g., based on weekly generation averages for each water year, peak diesel generation capacities required could approximate 37 MW at the 442 GW.h/year “low” scenario, about 55 MW under the 545 GW.h/year “mid” load scenario, and about 64 MW under the 610 GW.h/year “high” load scenario.

rather than on the costs per kW.h generated by the option[103]. At a simple level, the impacts of this approach can be demonstrated as follows:

- A non-diesel resource option will typically be initially examined in Section 3 (reflecting the March 2011 Charrette) to show costs per kW.h assuming full utilization of all generation, e.g., a wind resource costing $7.5 million per year and generating 50 GW.h per year will be shown to have an average cost of 15 cents per kW.h. This generation will occur throughout the year, and not vary depending on the level of hydro generation that occurs in any year. Lifetime present value costs for the resource (Levelized Cost of Energy or "LCOE") will similarly assume full utilization of the 50 GW.h during each year of the assumed project life.

- However, the 2011 Resource Plan in Sections 5 and 6 will examine the extent to which each non-diesel resource option's generation is forecast to displace diesel generation, taking into account forecasts grid loads each year, seasonal generation from existing and committed generation resources (other than the new non-diesel resource) and annual variability in hydro generation due to variable water conditions.

- For example, if in a given year the wind resource in the above example is only forecast to displace 25 GW.h, then the wind cost will be assessed in that year at 30 cents/ kW.h (not 15 cents), reflecting the cost per kW.h of diesel displaced (i.e., per kW.h of useful generation).

- Over the economic life of the each non-diesel resource option, a lifetime average present value cost per kW.h will be determined that reflects that lifetime useful generation able to displace diesel generation – this lifetime cost will reflect the forecast diesel generation without the wind resource (including annual seasonal and hydro variability, as well as sharply reduced diesel in years when mine loads are not forecast to be connected).

As discussed in Section 3, Full Utilization LCOE (i.e., assumes all generation fully used to displace diesel) and Forecast LCOE (i.e., looks at forecast ability to displace diesel generation) for any specific non-diesel resource option can vary significantly. Based on Yukon realities and load forecasts, the Forecast LCOE provides the assessment required of a resource option's ability to displace diesel generation.

[103] This approach is consistent with the assessments that Yukon Energy provided of the Mayo B Project during regulatory reviews, including review by the Yukon Utilities Board.

3.0 RESOURCE PLANNING OPTIONS – OVERVIEW AND SCREENING

3.1 INTRODUCTION

Section 3 and Sections 4 to 6 identify and evaluate resource planning options for implementation by Yukon Energy over the next five years (2011-2015), focusing on the need to determine:

- Preferred near-term major project options to be committed before 2015 to meet energy and capacity requirements in Yukon out to 2017;
- Appropriate planning activities during 2011-2015 to protect longer-term legacy resource development options for potential start of construction before 2021; and
- Appropriate planning activities during 2011-2015 to protect longer-term legacy resource development options for potential development after 2021.

Consistent with the 2006 Resource Plan, this planning level assessment is based on currently available information regarding grid and off-grid forecast and potential energy and capacity requirements (Section 2) and available resource supply alternatives. Several planning stages are required after the 2011 Resource Plan prior to any YEC decision to proceed with construction for any preferred project[104].

Reflecting the March 2011 Charrette outcomes, near and longer-term options are assessed concurrently in the context of overall Yukon requirements (i.e., off-grid as well as on-grid for all major power loads as reviewed in Section 2), agreed upon resource planning principles (as reviewed in Section 1), 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.

Section 3 reviews and screens current resource options as identified in the Charrette. Thereafter, the potential resource portfolios options are used to evaluate current resource planning options based on the four planning principles. The portfolio options examined are as follows:

- Section 4 - Default Diesel Portfolio;

[104] 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).

- Section 5 - Minimum GHG Emissions Portfolio Options; and
- Section 6 - LNG Transition Portfolio Options.

3.2 SCREENING OF CURRENT RESOURCE OPTIONS

Table 3-1 provides an overview of the various resource options considered at the March 2011 Charrette. Some of these options were considered in the previous 20-Year Resource Plan (Appendix A of the 2006 Resource Plan). Some options continue to be reviewed at this time as part of Yukon Energy's ongoing planning processes (e.g., separate ongoing assessments for completion by this fall are currently being undertaken of DSM/SSE resource options; ongoing assessments also continue for hydro enhancement options, wind, waste-to-energy, biomass and LNG). The 2011 Resource Plan has been prepared based on information currently available, recognizing that assessments remain subject (as was the case with the 2006 Resource Plan) to ongoing adjustment as new information and priorities emerge.

The 2011 Resource Plan assumes that Demand Side Management (DSM) and Supply Side Enhancement (SSE) measures will be implemented concurrent with any other resource supply options and a range of possible DSM/SSE program impacts are considered when assessing all resource supply options examined.

Each option in Table 3-1 is addressed in detail in a separate supporting attachment to either Appendix E (near-term options) or Appendix F (longer-term legacy options).

3.2.1 "Near-Term", "Long-Term Hydro" and "Long-Term Other" Resource Options

Table 3-1 characterizes resource options as "near-term" versus "long-term hydro" and "long-term other", addressing the potential ability of each option to be available in Yukon within the relevant planning period:

- **Near-Term Options** – These resource supply options are potentially available to start construction before the end of 2014 for in-service no later than 2017, based on consideration of potential ability to develop, licence and construct the option within this near-term planning period. As outlined in Table 3-1, the near-term options identified at the Charrette include DSM/SSE, diesel (the existing default option), hydro enhancements (includes Marsh Lake Storage, Atlin Storage and Gladstone Diversion), thermal-biomass (includes wood biomass and municipal solid waste), thermal-liquid natural gas (LNG), and wind (includes Ferry Hill and Mount Sumanik wind farm sites).

These options are examined further in Sections 4, 5 and 6, subject to the following screening refinements as reviewed in Appendix E:

- **DSM/SSE** – Yukon Energy is planning to proceed with a robust and aggressive DSM/SSE program in the very near-term as an integral element of the 2011 Resource Plan - based on current Yukon Government policy (as set out on in the Energy Strategy for Yukon and the Yukon Climate Change Action Plan) and current broad public support for conservation measures (including Yukon Utilities Board directives[105]). A successful DSM/SSE program will include a portfolio of specific DSM/SSE options that effectively reduce the requirements for demand and energy on the system and thereby reduce the diesel available to be displaced by other resource options – accordingly, in order to assess other resource options for resource planning purposes it is important to have an initial assessment of DSM/SSE potential impacts during the planning period.
    - DSM and SSE potential and related programs are currently being developed for later this year[106]. Yukon Energy is pursuing, for example, a LED streetlight program – 567 streetlights in Mayo, Dawson and Faro have been replaced with more energy efficient LED streetlights (a reduction in consumption approximately of 0.2 GW.h/year while maintaining safety and security attributes of streetlights).
    - Pending completion of this DSM/SSE program development, the 2011 Resource Plan has been prepared (see Section 4) assuming DSM/SSE program commencement by 2013 sufficient to secure a 67% reduction in annual non-industrial forecast medium load growth each year[107]. It is assumed for simplicity and pending completion of more detailed future analysis and program development, that assumed DSM reductions in ongoing non-industrial growth apply annually and equally to forecast non-industrial capacity and energy generation loads. As reviewed in Section 4, industrial DSM is also being pursued by Yukon Energy; however, no specific DSM assumptions have been adopted in the 2011 Resource Plan for industrial DSM.

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[105] Given YUB's previous orders and recommendations on DSM, and forecast diesel generation levels, it is reasonable to assume that meaningful and prudent DSM expenditures and actions will be supported by the regulator.

[106] YEC, YECL and YG are now proceeding with a detailed energy conservation potential review as required to determine by later this year the specific extent and cost/implication plans for feasible DSM programs to be implemented thereafter.

[107] YEC's DSM planning includes load reductions for industrial customers such as Minto, and therefore DSM savings are also expected for these loads. No specific industrial DSM estimates, however, are forecast or assumed in the current 2011 Resource Plan.

        - The 67% assumed reduction estimate is considered reasonable as BC Hydro currently is required (by the BC Clean Energy Act) to meet at least 66% of all load growth through DSM (separate from SSE). BC Hydro plans to exceed this DSM requirement by a combination of programs, standards and rate structures at unit energy costs for DSM averaging well under 10 cents/kW.h[108].

- **Hydro Enhancements** – Discussion at the Charrette identified three separate projects that YEC was working to develop in order to enhance its existing hydro facility generation: Marsh Lake Storage, Atlin Storage and the Gladstone Diversion. Due to the BC Government decision recently to designate Atlin River as a Class A park (and expectation that the designated park will include the river), work on the Atlin Storage project has currently ceased. For the remaining hydro enhancements, current potential earliest full year operation is assumed in Section 5 as follows (implies in-service later the previous year): Marsh Lake Storage (2015) and Gladstone Diversion (2018). Capacity enhancements provided by Marsh Lake Storage (about 1 MW) are considered in the current evaluation (no peak winter capacity enhancement is provided by Gladstone Diversion). In addition to the Marsh Lake and Gladstone hydro enhancement projects, Yukon Energy continues to pursue various other potential near-term hydro enhancement opportunities that are not addressed further in the current Section 5, including:
    - Amendments to the current Fisheries Act Authorization provisions for Aishihik generation which are estimated to provide potentially an additional 9 GW.h of annual energy on average from the Aishihik plant;
    - Transmission connection of the Yukon grid to the Taku River Tlingit owned Pine Creek Hydro Generating Station near Atlin, B.C. to take advantage of underutilized existing capacity plus undeveloped capability at the generating station. Transmission connection of the Yukon grid to the Taku River Tlingit owned Pine Creek Hydro Generating Station near Atlin, B.C. is being examined for various options. A 1.5 MW option would utilize surplus hydro from the existing TRTFN Pine Creek hydro plant,

[108] BC Hydro's DSM projections indicate similar material impacts from DSM on load growth in each major customer sector (residential, commercial and industrial); however, for each sector the impacts of specific DSM program components can vary a great deal In the 2008 DMS program filings ,for example, "Codes and Standards" DSM activities accounted for over 50% of the forecast residential DSM impacts, while sector-specific DSM "Programs" accounted for over 60% of the forecast commercial DSM impacts and over 80%of the forecast industrial DSM impacts. DSM "Rate Programs (the third and final major DSM component in the BC Hydro package) typically accounted for between about 15 and 20% of the DSM impacts in each major customer sector in the 2008 DSM program. BC Hydro's 2011 Integrated Resource Plan Draft 2010 Resource Options Report reviewed DSM energy-focused options with a resource cost ranging from 3.7 cents/ kW.h to 4.6 cents/kW.h.

with annual potential of 10 GW.h/yr over a 25 kV powerline. A 3.5 MW option would use the same exiting surplus hydro with a 2.2 MW expansion, with annual potential of 23 GW.h over a 35 kV powerline. A 8.0 MW option would use the expanded existing hydro plant plus a new 4 MW downstream plant with annual load potential of 52 GW.h over a 69 kV powerline[109]; and

- Current assessments in the 2011 Resource Plan assume that the Mayo Lake Enhanced Storage Project is committed and approved for 2012 (this project, which is assumed on average to provide an added 4 GW.h per year of grid hydro energy, has yet to proceed to regulatory approval stage and earliest implementation now would be in 2013).

- **Thermal options** – Current information for thermal wood biomass, thermal municipal waste and thermal LNG supply options is preliminary, particularly as regards feedstock supply development and/or arrangements. Initial pre-feasibility studies have been used in Sections 5 and 6 to assess the potential relevance of further work on any of these options, and further pre-feasibility analysis would likely be required prior to relying on any of these options for near-term supply. Each option is assumed to be located close to existing transmission.
  - **Thermal wood biomass** is considered in Section 5 based on information from the Charrette, available BC Hydro reports and a preliminary draft evaluation of opportunities to generate electricity in Yukon using wood biomass recently prepared for Yukon Energy by Morrison Hershfield. Lack of feedstock supply security has been identified as a significant project risk that will require mitigation prior to any wood biomass project development in Yukon. Based on the Morrison Hershfield report the economics of a 25 MW wood biomass thermal plant in Whitehorse by late 2014 (2015 first full year of operation) are assessed; in addition, a smaller 10 to 15 MW biomass plant scale option for the same in-service timing (located at either the Minto burn area or Whitehorse) is also assessed based on currently available information.
  - **Thermal municipal waste** is considered in Section 5 based on a recent draft summary report (provided to Yukon Energy by Morrison Hershfield) on use of municipal solid waste (MSW) as a feedstock in a thermal generation process at

[109] Yukon Energy has engaged in very preliminary discussions with representatives of the First Nation Development Corporation and a mutual interest has been expressed to continue discussions.

Whitehorse to provide increased firm electrical generation capacity as well as potential use of waste heat from the generation process in a future District Heating System. This "waste to energy" (WTE) option has been considered using the MSW/biomass feedstock and power generation scale ranges examined by the most recent Morrison Hershfield study (i.e., between 1.4 – 2.2 MW); for the purpose of Section 5 analysis, a 2.2 MW facility is assumed to be in-service by late 2014 (2015 first full year of operation) with MSW and wood biomass feedstock requirements and sale of district heat as per the Morrison Hershfield draft report.

- **Thermal LNG** is considered in Section 6 for a 25-30 MW LNG/natural gas power plant to be located at Whitehorse by late 2014 (2015 first full year of operation); the assumed plant scale reflects what is considered necessary to displace diesel under near-term loads with mines connected to the grid. Reflecting preliminary studies done to date[110], trucked-in LNG is assumed until local natural gas supplies are available (for initial costing, an LNG supply is assumed to be secured from facilities developed at Kitimat or at Fort Nelson, B.C., with the LNG then shipped to Whitehorse, Watson Lake [for YECL utility generation] and potentially off-grid mine sites). Finalizing the preferred sourcing of the LNG fuel supply is a significant issue to be addressed if this option is pursued.

- **Wind** – It is assumed that at most only one 20-21 MW scale wind project could be accommodated on the grid during the planning period, given the non-dispatchable nature of this energy supply option and the cost limits related to securing necessary added energy storage.

[110] Initial assessments utilized internal working papers prepared for Oil and Gas Resource Branch, Yukon Department of Energy, Mines and Resources, and studies for the developers of the Casino mine (Western Copper and Gold), as referenced in Appendix E, Attachment E4 regarding initial costing of an LNG supply to be developed at Fort Nelson, B.C., with the LNG then shipped to Whitehorse. As reviewed in Chapter 6 and Appendix E, Attachment E4, Western Copper and Gold is also examining the option of sourcing LNG by ship and truck from Kitimat (by truck through BC, or by ship/truck through Skagway) or Fort Nelson (by truck). Yukon Energy has been working recently with Western Copper and Gold to examine LNG supply chain options for Yukon suited for use by YEC, Western Copper and Gold (at Casino), YECL (at Watson Lake) and other off grid mine operations (see Section 6 reference Yukon Energy participating with Western Copper and Gold to retain Braemar Wavespec and Berger ABAB to evaluate LNG & Natural Gas supply chain options in lieu of diesel for electrical power generation fuel at various Yukon locations).

For simplicity, Section 5 evaluation of wind farm options focuses only on the following Ferry Hill options for assumed in-service by late 2014 (2015 first full year of operation)[111]:

- 21 MW option connected to the Stewart Crossing south substation, assuming 5 MW of added diesel rotary uninterruptible power (DRUPS) is required for reliability if this level of wind resource is developed[112]; and
- 10.5 MW option connected to the Stewart Crossing north substation, assuming that no added DRUPS is required for reliability so long as the wind resource development is limited to this scale on the grid.

- **Long-Term Hydro Options** – These greenfield resource supply options are potentially available to start construction before 2021 to provide new low cost, clean and reliable long-term electricity supply in Yukon, subject to adequate and reasonably assured long-term load levels to utilize the new energy supply. These potential new greenfield hydro sites require up to 10 years or more to plan, secure regulatory approvals and develop; accordingly, if such options are to be available to start construction before 2021 there is a need to begin site specific planning processes today that are sustained as required throughout the near-term. These options are examined further in Section 5, subject to the following screening refinements as reviewed in Appendix F identifying total potential supply exceeding 6,800 GW.h/year from hydro sites with estimated full utilization costs (with transmission) below 15 cents/kW.h (2009$).

  Figure 3-1 indicates the location of these and other potential hydro sites that YEC has examined, as well as the relative location of the Casino, Selwyn, MacTung and Northern Dancer off-grid mine projects[113].

[111] YEC continues to examine the Mount Sumanik 20 MW wind farm option, and if developed rather than Ferry Hill its overall generation and costs would likely be similar to those assumed in Section 3 for Ferry Hill.

[112] In assessing either Ferry Hill or Mount Sumanik 21 or 20 MW wind farms, it is assumed that approximately 5 MW of spinning reserve is currently available and that (regardless of wind resource use) about 10 MW of existing non-base loaded hydro units would be converted to synchronous condenser peaking units (see Appendix E, Attachment E5). A 21 MW wind farm is then assumed to require that a further 5 MW DRUPS be added to the grid to provide adequate reliability.

[113] Hydro sites that are protected in the Yukon First Nation Final Agreements include elements of Granite Canyon (Selkirk First Nation), Hess (Na-Cho Nyak Dun First Nation), Morley (Teslin Tlingit Council First Nation), Aishihik (includes various related projects such as the Gladstone Diversion – Champagne/Aishihik First Nation and Kluane First Nation), Drury Lake/Creek (Little Salmon/Carmack First Nation) and North Fork (Tr'ondek Hwech'in First Nation). Upper Canyon on the Frances River, Finlayson River and Hoole/Slate are classed as "interim protected" (i.e., are in traditional areas of First Nations that do not today have a land claims agreement).

- **Small Hydro Options (<10 MW; up to 70 GW.h/year at 20-22cents/ kW.h)** – Aside from potential transmission connection to underutilized and undeveloped hydro capacity near Atlin, B.C., small scale hydro options are identified in the Southern Lakes region (near Tutshi Lake, B.C.) at Moon Lake and Tutshi River or Tutshi (Windy Arm). Annual energy potential for each site approximates 30- 39 GW.h/year with full utilization life cycle costs (with transmission to the Yukon grid) estimated at 20-22 cents/kW.h.
- **Medium Hydro Options (11-60 MW; over 2,070 GW.h/year at less than 15 cents/kW.h)**
  - Four sites or schemes investigated by Yukon Energy (or NCPC in the past) have estimated full utilization costs (with transmission) below 10 cents/ kW.h (2009$) and offer over 850 GW.h/year of average annual sustainable energy supply after considering duplication among these sites. These sites include Hoole Canyon with Storage [275 GW.h/year], Slate Rapids [266 GW.h/year], Granite Canyon Small [400 GW.h/year] and Finlayson [129 GW.h/year].
  - A further five medium size sites or schemes with full utilization costs between 10 and 15 cents/kW.h offer over 850 GW.h/year of additional average energy supply after considering for site modifications already addressed in the sites with costs below 10 cents/kW.h. These include Combined Slate Rapids [361 GW.h/year] and another Slate Rapids site [156 GW.h/year], Two Mile Canyon [280 GW.h/year], Ross Canyon [181 GW.h/year], and False Canyon [370 GW.h/year][114].
  - A further two medium size sites north of Watson Lake have full utilization costs less than 15 cents/kW.h if exceptionally high transmission costs to connect to the existing grid are excluded. These sites are Middle Canyon [200 GW.h/year] and Upper Canyon [176 GW.h/year].

[114] The last site (False Canyon) is highly impacted by transmission distance to east of the current grid.

- Recently, the developer of the Northern Dancer mine has reported on studies for the Morley River site with potential generation exceeding 300 GW.h per year and costs under 10 cents/kW.h[115].

- **Large Hydro Options (>60 MW; over 4,740 GW.h/year at less than 15 cents/kW.h)**
  - Five sites or schemes have estimated full utilization costs (with transmission) below 10 cents/kW.h (2009$) and offer over 3,540 GW.h/year of average annual sustainable energy supply after considering duplication among these sites and after considering for site modifications already addressed in the medium size sites. These include Fraser Falls Low [700 GW.h/year] and Fraser Falls High [2,100 GW.h/year]; Slate Rapids/Hoole [459 GW.h/year]; and Granite Canyon Low [600 GW.h/year] and Granite Canyon High [1,783 GW.h/year].
  - A further three medium size sites or schemes with full utilization costs between 10 and 15 cents/kW.h offer over 1,200 GW.h/year of additional average energy supply after considering for site modifications already addressed in the sites with costs below 10 cents/kW.h. These include Detour Canyon [435 GW.h/year] and Detour Canyon with Storage [585 GW.h/year], and Liard Canyon [659 GW.h/year][116].

[115] The medium scale hydro sites currently screened by Yukon Energy do not include Morley as past Yukon Energy information for this site indicated only about 22 GW.h/year of potential average annual generation based on reasonable development options with impacts confined within Yukon (i.e., not involving trans-border impacts in BC). Largo Resources Limited's public information regarding the Northern Dancer mine development indicates more recent hydro site potential investigations of the Morley River below Morley Lake suggesting a potential for over 300 GW.h/year generation at an average cost of less than 10 cents/kW.h. Yukon Energy has not to date reviewed the Largo Resources study. Recent (October 2011) discussions with Northern Dancer, however, indicate that the Morley River hydro option is no longer being considered (in the absence of grid connection to BC, which would allow this mine to be located in BC and to secure BC industrial rates, transport of liquefied natural gas (LNG) to the site is being considered).

[116] The last site (Liard Canyon) is highly impacted by transmission distance to the east of the current grid.

- **Other Long-Term Options** – These long-term resource supply options require external action by others to be considered potentially available for development before 2021. More specifically, ability to pursue these options further requires new information (e.g., successful exploration results for geothermal[117]), new technology (e.g., a cost-effective clean coal technology, proven and cost-effective mini-nuclear plant technology and/or solar technology suitable for Yukon use), or other external action (e.g., indigenous coal development close to the grid in Yukon[118]; commitment by others to provide natural gas in southern Yukon through an Alaska Highway pipeline and/or Eagle Plains development[119]; commitment by others to connect Yukon's grid with grids in British Columbia[120] or Alaska). These options merit ongoing monitoring of developments, but are not considered further in Section 3.

3.2.2 Key Planning Principle Characterization of Resource Options

Resource options are also initially characterized in Table 3-1 using each of the four key planning principles agreed to by Charrette participants[121].

- **Reliability** – Reliability is assessed in Table 3-1 regarding winter peak and reserve capacity, as well as security of resource supply and in-service timing for new development.
  - Diesel and thermal options (biomass, LNG) provide high reliable winter peak and reserve capacity, while wind options do not provide reliable winter peak or reserve capacity (and therefore require other concurrent resource measures to ensure reliable capacity).

[117] Geothermal opportunities offer future potential to provide significant low cost, clean, and reliable long-term electricity supply in Yukon if successful exploration can define appropriate opportunities close to the grid. Section 5.1.2 reviews a preliminary resource assessment and prioritization of sites recently undertaken for Yukon energy. As reviewed in Appendix F, Attachment F2, considerable costs would likely be required to carry out the necessary ongoing exploration and confirmation drilling to locate and then develop geothermal as a generation resource in Yukon. Funding for this type of development activity at the scale likely to be needed is not typical for a regulated utility such as Yukon Energy. Accordingly, the 2011 Resource Plan does not provide any specific major proposed activities for geothermal beyond ongoing monitoring of related activities in Yukon.

[118]Monitoring indigenous Yukon coal resource development as well as evolving clean and small scale coal technology also merits attention, given Yukon coal resources that exist in close proximity to the grid.

[119] Proponents of the Alaska Pipeline Project provided a project schedule in fall 2011 community meetings in Alaska indicating first gas in 2020 and full gas in 2021, assuming an October 2012 FERC filing and project sanction before mid-2015 (see Section 6). There is currently no timing or plan for development of Eagle Plains, but potential options may emerge tied to development of a major new load such as the Casino mine.

[120] Appendix F, Attachment F2 reviews a conceptual-level study done for YEC of a transmission interconnection between Yukon and B.C. Four alternatives were considered, with costs ranging from $1.2 billion to $2.4 billion.

[121] Further details of this initial characterization are provided in Appendix B, Attachment B-1.

- Regulatory approval risk affecting timing and cost is characterized as high for near-term hydro enhancement options and longer-term medium/large greenfield hydro options – highlighting a key concern affecting in-service timing for these options.

- **Affordability** – Affordability is assessed in Table 3-1 as discussed at the Charrette based on an option's full utilization levelized cost of energy ("Full Utilization LCOE"[122]) per kW.h over the option's economic life, assuming adequate load throughout each year of the project life to ensure full utilization of all energy supplied by the option to displace (in the current Yukon context) diesel generation that would otherwise have been required.

  - DSM/SSE and certain hydro options (hydro enhancements and large greenfield hydro) are characterized with high affordability (i.e., Full Utilization LCOE generally less than 10 cents/kW.h), while diesel and thermal-biomass options are characterized with low affordability (i.e., Full Utilization LCOE at 20 to over 30 cents/kW.h).
  - As discussed below, further evaluation of affordability for each option is to consider the extent to which the energy supplied is forecast to be utilized in an effective manner based on forecast loads as reviewed in Section 2 (i.e., seasonal load and hydro supply forecasts [including consideration of annual hydro variability] as well as near and long term load forecasts). For example, large scale greenfield hydro generation projects are characterized with "high affordability" in Table 3-1 (i.e., levelized costs of 5-11 cents/kW.h), assuming full utilization of all generation; however, generation from these large scale greenfield hydro projects would clearly not come close to being "fully utilized" under current forecast grid loads – and until reasonable levels of utilization are forecast over 20-30 or more years, such capital intensive projects would in reality be highly unaffordable in Yukon.
  - In the context of the 2011 Resource Plan, energy generated by a non-diesel option that fails to displace diesel generation otherwise required has no economic value (i.e., it is "wasted" energy that fails to save costs for the utility or its ratepayers and has no value in meeting forecast load requirements).

[122] LCOE indicates on a consistent and comparable basis each option's overall costs per kW.h in current dollars ($2010). It includes capital and operating costs and, where specified, any related transmission, storage or capacity costs. This cost is subject to ongoing annual inflation for each subsequent year of operation in order to assess costs over the option's economic life. This cost does not mean that Yukon Energy or ratepayers would face this specific cost per kW.h during each year of operation (while LCOE may reflect annual costs for fuel intensive options, capital intensive options will have costs per kW.h above LCOE at the outset, declining over time to be less than LCOE). LCOE assessment for each option in the 2011 Resource Plan assume the same cost of capital (6.56% blended cost of debt and equity as last approved by the YUB for YEC's 2009 GRA) and general inflation at 2% per year.

- **Flexibility** – Flexibility is assessed in Table 3-1 based on ratepayer risks regarding mine load reductions. As reviewed in Section 2.4, flexibility can also be an important factor on the Yukon grid in accommodating diesel generation displacement during the summer/fall season and under the wide range of annual hydro generation conditions.
    - Diesel and thermal-LNG options show high flexibility, while thermal-biomass, wind and long-term hydro options show low flexibility (reflecting the capital intensive nature of these options).
    - Options showing low flexibility in Table 3-1 may show "Forecast LCOE" (LCOE based on costs per kW.h of diesel displaced) that is materially higher than Full Utilization LCOE to the extent that forecast grid loads are unable to fully utilize the option's new generation and the new option's costs are not flexible in response to grid load changes.
- **Environmental Responsibility** – Environmental responsibility is assessed in Table 3-1 based primarily on reduction of GHG emissions in Yukon.
    - Hydro enhancements, thermal-biomass and wind options show high environmental responsibility, while diesel shows low environmental responsibility reflecting higher GHG emissions than any other option.
    - Environmental responsibility issues are also noted in Table 3-1 regarding the large footprint associated with longer-term greenfield hydro projects and the related impacts on land, waters and people. Concerns have been raised by local communities and/or First Nations regarding potential adverse environmental impacts on lands, water and people regarding each of the hydro enhancement project options - these concerns will be addressed in any environmental assessment and permitting by regulatory authorities, and are the basis for the regulatory reliability issues noted earlier for these projects. No major environmental impact issues regarding land, water or people that might affect project timing or viability have been identified to date for the other near-term renewable options (wind and wood biomass). In regard to longer-term resource options, hydro sites or schemes screened above for longer-term consideration with estimated full utilization costs below 15 cents/kW.h have the following range of potential reservoir areas and salmon fisheries related issues:
        - **Small Hydro Option (<10 MW)** – These options do not involve any material new inundation, and no salmon-related fisheries issues.

- **Medium Hydro Options (11- 60 MW)** – Finlayson has smallest reservoir area (<11 km^2)[123]; several options have between 60 and 85 km^2 of reservoir area (Hoole Canyon with Storage[124], Two Mile Canyon[125], Ross Canyon and False Canyon[126]). Slate Rapids has 102 km^2 and Combined Slate Rapids has 162 km^2 [127]. Finlayson and False Canyon are the only options with no salmon-related fisheries issues.
- **Large Hydro Options (>60 MW)** – Detour Canyon has the smallest reservoir area (70 km^2). Four sites have between 119 and 147 km^2 of reservoir area (Slate Rapids/Hoole, Detour Canyon with Storage, Liard Canyon and Fraser Falls Low). Fraser Falls High has 372 km^2 of reservoir area. Liard Canyon is the only option with no salmon-related fisheries issues.

The overall resource planning objective is to select a portfolio of resource options that achieves an appropriate balance among the four key principles based on currently known near-term and longer-term load requirements throughout Yukon (including off-grid industrial loads) during the 20-year planning period (2011-2030).

Reliability is addressed as a fundamental requirement in each resource option portfolio based on forecast loads and currently committed grid resource availability as reviewed in Section 2. Flexibility is addressed by subjecting each resource option portfolio to potential changes in mine loads beyond the forecasts in Section 2. The major remaining challenge is to balance affordability and environmental responsibility in the selection of resource options.

- In the longer-term, Table 3-1 indicates that new greenfield hydro options offer the potential in Yukon to provide both low cost and low GHG emissions, subject to securing adequate load to utilize effectively this new generation over 30+ years and subject to successfully addressing regulatory risks affecting timing and costs. Geothermal and clean coal are identified in Table 3-1 as other long-term options that might, subject to successful exploration (geothermal) or new technology (clean coal) also provide in Yukon both low cost and low GHG emissions.

[123] Noted permafrost challenges. Minor potential impact on settlement land.
[77] Material new access to previously inaccessible wilderness.
[78] Impact on settlement land.
[126] Ross Canyon, False Canyon and Middle Canyon are not on protected sites (all other sites are protected); False Canyon and Middle Canyon have no salmon present in river – all other sites have salmon in river. False Canyon and Middle Canyon also have no permafrost challenges. Ross Canyon would have effects on harvesting activities, small heritage impact and impacts on tourism.
[127] Noted permafrost challenges. Also, Slate will dewater significant length of Pelly River between dam and powerhouse and likely would require mitigation measures to address. Material potential impact on settlement land.

- In the near-term, Table 3-1 highlights the high cost (approximating 30 cents/kW.h) and high GHG emissions associated with diesel generation; other than hydro enhancements (which have high regulatory risks affecting in-service timing), all near-term options to diesel show Full Utilization LCOE ranging from 15 to over 30 cents/kW.h, indicating costs for near-term incremental generation well above current average grid generation costs. Near-term reductions in GHG emissions relative to diesel are offered by all non-diesel options; however, aside from hydro enhancements, low GHG emissions are offered only by thermal-biomass and wind options that display high capital costs and low flexibility. Sourcing fuel supply remains a significant issue for both thermal-biomass and thermal-LNG and further pre-feasibility analysis would be required prior to relying on either of these options for near-term supply (i.e., for start of construction before the end of 2014).

3.3 OVERVIEW OF SUBSEQUENT SECTIONS

Sections 4 to 6 examine three broadly different resource portfolio options in order to gain insight into the basic choices available today:

- Section 4 looks at the Default Diesel Portfolio Option, focusing on defining grid economic impacts, Yukon GHG emissions impact, and longer-term development considerations for this basic default option. Assumed DSM/SSE is outlined in this section, and is included in subsequent analysis in Sections 5 and 6 as a resource option that Yukon Energy is assumed to pursue no matter what other resource options are developed[128].

- Section 5 looks at Minimum GHG Emissions Portfolio Options, focusing on potential renewable resource development responses to the forecast energy and capacity requirements as one path to reduce reliance on diesel generation. Grid economic impacts, Yukon GHG emission impact and longer-term development considerations are reviewed for these portfolio options. Focusing on longer-term affordability and GHG emission reduction, greenfield hydro resource options are examined to identify ongoing planning activities during the next five years to protect longer-term legacy resource development options for potential start of construction before 2021.

- Section 6 looks at LNG Transition Portfolio Options, focusing on an option to retain flexibility similar to that provided by diesel generation while materially reducing the costs and GHG

[128] In the past, reflecting YUB review after the Faro mine closed in 1993, DSM tended to be suspended as a utility planning cost during periods of surplus hydro on the grid. No attempt has been made in the 2011 Resource Plan to assess under what conditions future DSM/SSE as assumed in the analysis might be similarly suspended in future.

emissions relative to the Default Diesel Portfolio. Near-term loads under each load scenario are addressed, while also encouraging the ability to plan for, and pursue, cost effective and environmentally responsible wind, hydro or other renewable legacy resource development when feasible over the longer-term planning horizon. Grid economic impacts, Yukon GHG emission impact and longer-term development considerations are reviewed for these portfolio options.

Focusing on the near-term capital intensive options that have low GHG emissions (hydro enhancements, thermal-biomass, and wind), near-term assessments in Section 5 (Minimum GHG Emissions Portfolio Options) look at Forecast LCOE (i.e., the extent to which the new generation will be utilized at forecast loads) and initial operating year costs (i.e., costs ratepayers would face in the initial years of operation).

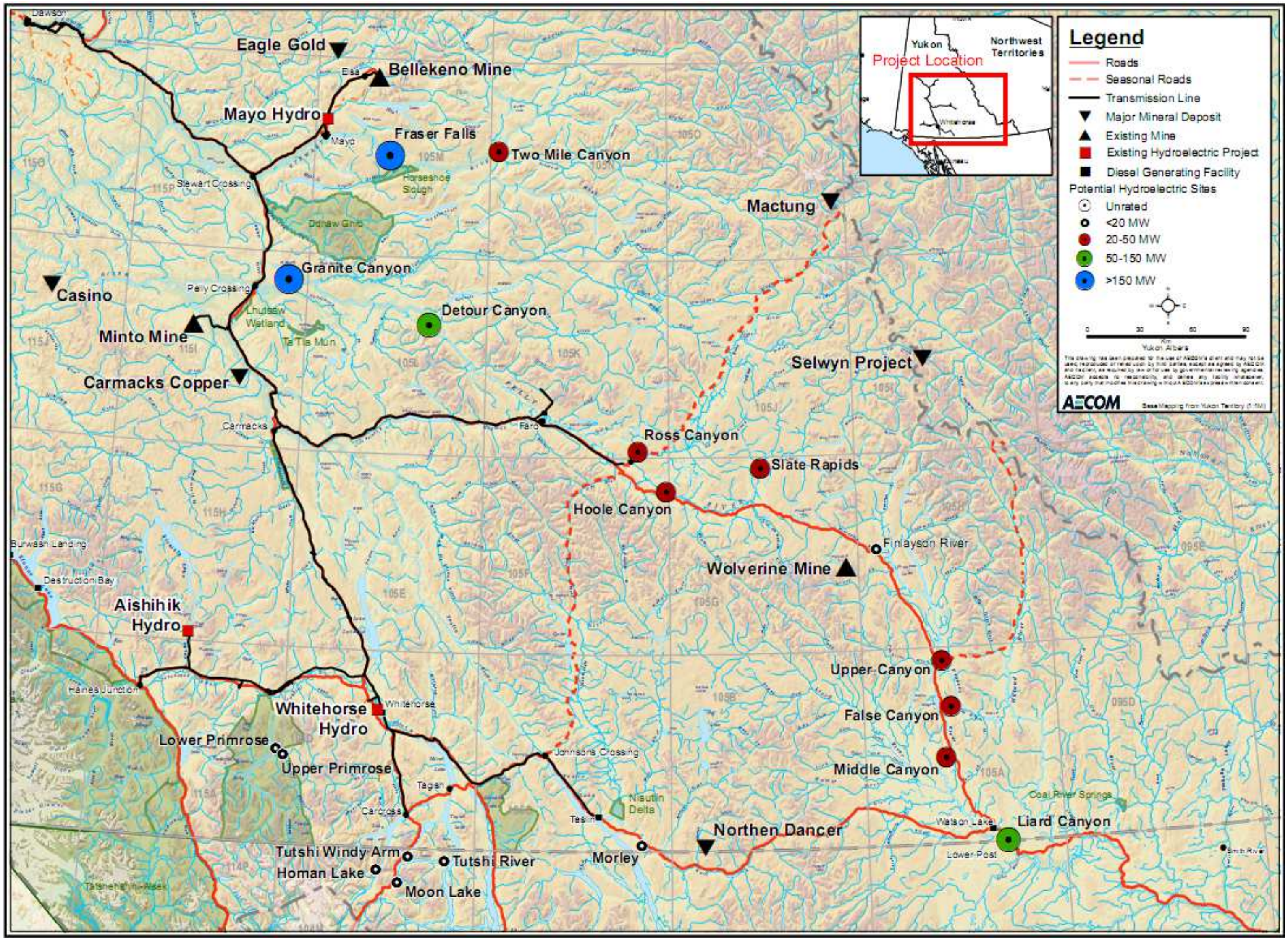
- Both Forecast LCOE and initial operating year costs per kW.h for these options as reviewed in Section 5 are considerably higher than the Full Utilization LCOE estimates in Table 3-1.
- As reviewed in Section 5, high Forecast LCOE costs for these renewable resource options reflect low flexibility to address loss of mine loads after 2021 (as well as low forecast diesel generation displacement opportunities during summer/fall months), while high operating year costs per kW.h in the initial operating years (i.e., 2015 to 2020, when mine loads are assumed to be connected to the grid) reflect the capital intensive nature of these options.

Table 3-1: Range of Resource Supply Options & Initial High Level Characterization

AVAILABLE OPTIONS		RELIABILITY Reliable winter peak capacity, & reliable development (timing & cost)	AFFORDABILITY c/kW.h ($2010) if fully utilized	FLEXIBILITY Ratepayer cost risks re Mine Load Reductions	ENVIRONMENTAL RESPONSIBILITY Env. impact mitigation - reduction of GHG Emissions
NEAR-TERM – 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. 30c/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
LONG-TERM HYDRO - (greenfield) potentially available start 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 to11 c/kW.h	LOW – not flexible; high capital costs req's sustained demand (30+ yrs)	MEDIUM – HIGH – minimal emissions; large footprint
OTHER LONG-TERM (require information, technology or other external action to be considered potentially available before 2021)	Geothermal (exploration)	HIGH re: energy & capacity LOW re: development risk as depends on successful exploration	HIGH - low cost to build and operate LOW– high exploration costs	LOW – not flexible; high capital cost req's sustained demand; Not dispatchable	HIGH – minimal emissions/ footprint
	Clean Coal	HIGH - baseload energy & capacity	MEDIUM to HIGH	LOW – relatively inflexible; issues re: Scalability	LOW-MEDIUM - Need new tech. to prevent GHG emissions
	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 cents & 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.

Figure 3-1: Location of Existing Grid, Potential Hydro Sites, and Various Existing & Potential Mines



Legend: Large Blue circles >100 MW; Purple circles 60-100 MW; Red circles 20-60 MW; Black circles <20 M.

4.0 DEFAULT DIESEL PORTFOLIO

4.1 DEFINING THE PORTFOLIO

The near-term 2011 Resource Plan assessment of grid options acknowledges that diesel is currently the default generation resource option in Yukon (i.e., in the Yukon context diesel is the reliable, established and available supply option against which other new supply options must be assessed). Assuming replacement of diesel generation assets on retirement, today's existing and committed grid generation resources can fully supply the near-term forecast loads including new grid connected mine loads reviewed in Section 2.

Further, as reviewed in the Section 3.2 screening of resource options, the 2011 Resource Plan assumes that DSM/SSE programs will be implemented concurrent with any other resource supply option developed at this time.

Accordingly, the near-term resource planning assessment in effect establishes diesel and an assumed DSM/SSE development together as the baseline portfolio against which all other near-term resource options are to be assessed.

- **Diesel – Existing Supply Default Option** – Due to high operating costs and high GHG emissions, diesel is not considered a preferred or acceptable option in Yukon to supply long-term baseload generation[129]. However, unless other less costly and/or lower GHG emission sources of grid generation are developed in the near-term, available diesel generating capacity on the grid will remain the effective default option to supply baseload energy requirements when grid load surpasses what existing renewable resources can supply[130]. Diesel today is also the default option in all off-grid power supply situations in Yukon.

  While it is not a preferred resource to supply ongoing baseload generation requirements, diesel is considered a low capital cost option to supply the grid capacity that is required for reserves (including security of local community supply) or occasional peaking use. Over time new diesel generating facilities will need to be provided for this purpose simply to replace diesel unit

[129] Baseload diesel generation is diesel generation required throughout major portions of the year under long-term average water conditions.

[130] As reviewed in Appendix D and elaborated on in Attachment E2, existing diesel capacity is more than adequate to supply forecast energy requirements under each of the near-term load forecast scenarios.

capacity upon retirement of existing units, or as otherwise required, solely to address grid capacity planning shortfalls.

- **DSM/SSE** – As reviewed in the Section 3.2 screening of resource options, for the 2011 Resource Plan DSM/SSE is assumed to be in place when assessing all other near-term resource options, and is further assumed to secure a 67% reduction in annual non-industrial grid load growth (both capacity and energy) each year starting in 2013[131]. For the purpose of 2011 Resource Plan annual cost impact assessments under each portfolio, it is further assumed that DSM/SSE programs incur an average annual cost equal to 7.5 cents/ kW.h (2010$) of assumed energy load reduction[132].
    - Pending completion of current DSM/SSE studies and program development, no costs have been estimated for specific DSM/SSE programs in the current 2011 Resource Plan for this DSM/SSE resource program (these will be addressed later after completion of the current DSM/SSE studies).
    - YEC is developing DSM with industrial customers. Although no estimates are provided in this analysis for industrial DSM savings, it is anticipated that there are some likely added DSM-related load reductions (potentially in the order of 10%) related to forecast industrial loads on the grid.

Figure 4-1 summarizes forecast utility annual default diesel energy requirements for on grid and off-grid loads[133] for scenarios with and without DSM/SSE. This illustrates the extent to which forecast diesel energy generation is assumed to be reduced as a result of the assumed DSM/SSE under each of the forecast load scenarios: Base Case, Scenario A and Scenario B (based on current best available forecasts, after 2021 load levels and growth assumptions for Base Case, Scenario A and Scenario B are the same and default diesel energy requirements are therefore also the same after 2021).

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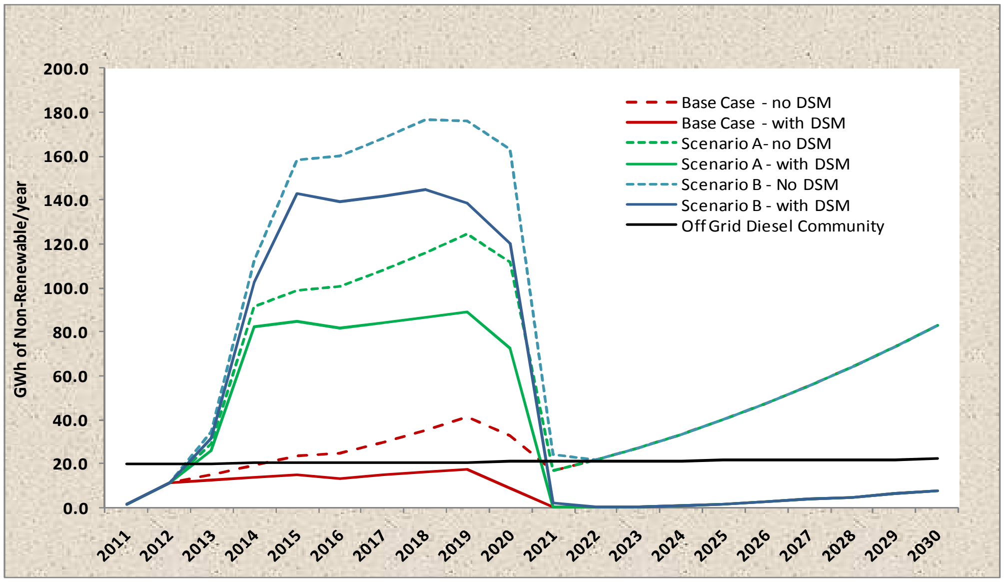
[131] This reduction is equivalent to lowering the non-industrial growth from 2.26%/year to about 0.75%/year, a very modest growth rate that is below the low growth rate scenario for non-industrial loads. Pending completion of the current detailed conservation potential review study, the assumed DSM/SSE is considered to provide a reasonably conservative assessment of overall DSM/SSE impacts over the planning period and to be affordable (low cost), reasonably flexible, reasonably reliable and environmentally responsible. When specific costs for programs are developed over the coming year the projected impacts will be refined. It is understood that actual DSM/SSE programs may well result in differential impacts on energy versus capacity growth rates.

[132] An average annual cost of 7.5 cents/kW.h (2010$) of new annual DSM/SSE load reduction has been assumed simply to ensure that a reasonable cost is included in the annual cost impact assessments provided in the 2011 Resource Plan; it is assumed that DSM/SSE costs are amortized over 10 years, i.e., no cost carryover after 10 years. [The average cost for all DSM/SSE is assumed to be considerably less that a potential target cost limit not to exceed about 50% of avoided costs for diesel and other resource supply options, i.e., for the grid, not to exceed 50% of 20 to 30 cents/kW.h (2010$). BC Hydro projected costs for various DSM options in the 2011 IRP were less than 5 cents/kW.h.].

[133] Each grid diesel energy load forecast scenario reflects long-term average water year hydro generation capability for existing and currently committed hydro generation resources at Whitehorse, Aishihik and Mayo.

Figure 4-1: Diesel Energy Requirements (Grid & Off-Grid Utility) for Resource Plan Scenarios: 2011-30



Diesel Energy Requirement	**2011**	**2015**	**2020**	**2025**	**2030**
Base Case (GWh)					
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
Scenario A (GWh)					
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
Scenario B (GWh)					
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
Off Grid Diesel Community (GWh)	19.9	20.4	20.9	21.5	22.1
Diesel Energy Cost (Fuel & O&M)					
Base Case ($ millions)					
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
Scenario A ($ millions)					
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
Scenario B ($ millions)					
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
Off Grid Community ($ millions)	5.9	6.6	7.5	8.6	9.9

Table 4-1 provides forecast annual diesel generation by year for each of the load scenarios, showing for each year the forecast range between the assumed DSM/SSE versus no DSM/SSE. Provision of this range is used to test the sensitivity of other resource option assessments to the outcome of the DSM/SSE program that is currently being developed. Table 4-1 also shows the assumed grid load reduction impact (GW.h) each year of the assumed DSM/SSE for non-industrial grid loads.

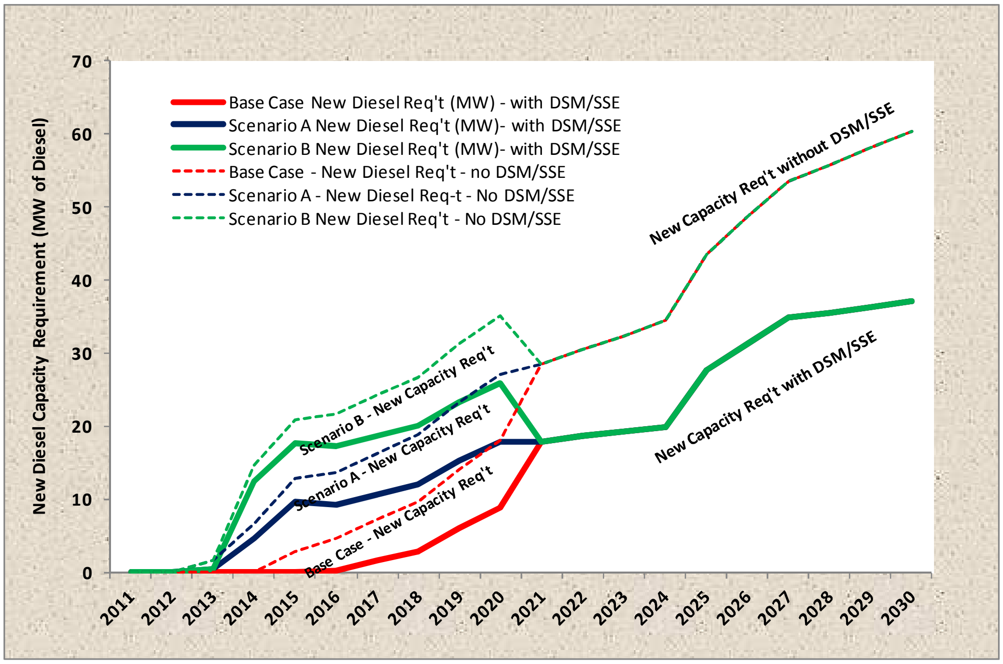
Table 4-1: Forecast Grid DSM/SSE & Diesel Generation by Load Scenario – 2011-2030 (GW.h/year)

Forecast Years	Base case no DSM	Base case with DSM	Scenario A no DSM	Scenario A with DSM	Scenario B no DSM	Scenario B with DSM	Non-industrial DSM/SSE
2011	1.5	1.5	1.5	1.5	1.5	1.5	0.0
2012	11.5	11.5	11.5	11.5	11.5	11.5	0.0
2013	15.1	12.7	29.0	25.9	34.8	31.5	5.4
2014	19.2	13.9	91.7	82.6	112.1	102.5	10.9
2015	23.7	15.2	98.9	84.9	158.1	142.9	16.6
2016	24.8	13.4	100.5	81.7	159.9	139.3	22.3
2017	29.9	14.7	108.2	84.1	168.1	142.0	28.2
2018	35.5	16.2	116.2	86.6	176.5	144.7	34.3
2019	41.5	17.6	124.4	89.1	176.2	138.9	40.5
2020	32.5	8.7	112.0	72.5	163.3	120.6	46.8
2021	16.6	0.0	16.6	0.0	24.0	2.0	53.2
2022	21.6	0.0	21.6	0.0	21.6	0.0	59.8
2023	27.3	0.3	27.3	0.3	27.3	0.3	66.6
2024	33.5	1.0	33.5	1.0	33.5	1.0	73.5
2025	40.3	1.8	40.3	1.8	40.3	1.8	80.6
2026	47.7	2.7	47.7	2.7	47.7	2.7	87.8
2027	55.7	3.7	55.7	3.7	55.7	3.7	95.2
2028	64.2	4.9	64.2	4.9	64.2	4.9	102.7
2029	73.2	6.1	73.2	6.1	73.2	6.1	110.4
2030	82.8	7.5	82.8	7.5	82.8	7.5	118.3

Diesel generation varies in the near-term under the above load scenarios during the years 2013 to 2021, reflecting varying assumptions as to connected industrial loads. In summary, the maximum grid diesel energy generation displacement opportunities are forecast during 2015-19 (under average water year conditions) with DSM/SSE from 13 to 18 GW.h/year under the Base Case (non-industrial load and currently connected mines), from 82 to 89 GW.h/year under Scenario A (Base Case with Victoria Gold), and from 139-145 GW.h/year under Scenario B (Base Case plus Victoria Gold, Carmacks Copper, WHCT).

Figure 4-2 highlights forecast new default diesel capacity requirements by year on the grid for each load scenario with and without DSM/SSE. Figure 4-2 and accompanying table 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 (as discussed in Section 2.3.2 and depicted in Table 2-2 and Figures 2-8 and 2-9[134]).

Figure 4-2: New Diesel Grid Capacity Requirements for Resource Plan Scenarios: 2011-30



	2011	2015	2020	2025	2030
New Diesel Capacity Requirement (MW)					
With DSM/SSE					
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
Without DSM/SSE					
N-1	0.0	2.9	18.0	43.5	60.4
Base Case	0.0	2.9	18.0	43.5	60.4
Scenario A	0.0	12.9	27.1	43.5	60.4
Scenario B	0.0	20.9	35.1	43.5	60.4
Diesel Capacity Additions ($Millions)[1]					
With DSM/SSE					
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
Without DSM/SSE					
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]).

[134] Section 2.3.2 reflects circumstances without DSM/SSE.

4.2 GRID ECONOMIC IMPACTS

For overall cost comparison of diesel with other generation options the 2011 Resource Plan examines generation resource Portfolio options (i.e., different mixes of resource options to meet the forecast grid energy and capacity requirements). Each portfolio is designed to meet the full grid generation requirement each year under the specified forecast scenario; accordingly, whatever energy or capacity is not supplied by non-diesel resource options is supplied by diesel and the related diesel costs are included in the portfolio assessment unless otherwise noted.

The overall cost comparison of diesel and other portfolio options focuses on the following assessments for each Portfolio:

- **Present Value Assessment:** An overall present value (PV) assessment is provided for each portfolio to show PV (2010$) total grid generation costs (energy and capacity) required to meet incremental capacity and energy requirements over the 20-year planning period (2011-2030) under the three near-term load scenarios as well as both with and without assumed DSM/SSE. The PV assessment adopts a consistent economic impact framework, as reviewed below, to compare the Default Diesel Portfolio with other portfolio options over the 20-year planning period.
  - Diesel fuel and O&M costs per kW.h are assumed (2010$) at approximately 28 cents/kW.h[135]; diesel capacity requirements are also included in the PV costs for each portfolio[136].
  - Review of diesel option costs relative to other resource options and review of annual cost impacts for different resource portfolios that include diesel generation need to look at sensitivity to changes in the diesel fuel price forecast. Experience over the past few years as well as the past few decades has shown periods of high oil price volatility as well as periods when the oil price was relatively stable. The use of one number (28 cents/kW.h

[135] The 2011 Resource Plan assumes diesel fuel and O&M costs per kW.h (2010$), escalated at general inflation after 2010 (2% annual inflation assumed), based on fuel and other O&M costs approved in current rates (per 2009 GRA) for the WAF grid (28 cents/kW.h is a 50/50 blend of existing units at 30 cents/kW.h and more efficient new units assumed at 26 cents/kW.h, with O&M costs accounting for about 3.0 cents/kW.h for existing units and 2 cents/kW.h for new units – see Appendix E, Attachment E2).

[136] Diesel capital costs required for new capacity are included in the PV assessment; each portfolio is credited in the PV assessment with any present value savings affecting diesel capacity capital costs during the 20-year planning period. New diesel capacity is assumed to cost $1.5 million per MW (2010$).

in 2010$) in the 2011 Resource Plan for diesel fuel and O&M is done to set a consistent benchmark for comparison with other resource options, and ignores the considerable uncertainty affecting future diesel fuel prices due to changing world market conditions – including risk that oil prices will slump in the near-term due to depressed world markets.

  - The 2011 Resource Plan diesel fuel prices are based on escalation of YEC's approved 2009 diesel fuel prices [96 cents/litre at Whitehorse] at 2% per year inflation.
  - 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)[137].

- The range of load scenarios included assists in testing sensitivity to different load levels. Assessment with and without assumed DSM/SSE identifies a range of potential DSM savings as well as related impacts on overall PV costs based on two DSM/SSE extremes over the resource planning period (i.e., impact of a portfolio on loads and overall costs without any DSM and impacts on loads and overall costs with a robust and successful DSM program).
- As reviewed earlier, the current PV assessments assume that DSM/SSE programs incur an average annual cost equal to 7.5 cents/kW.h (2010$) of assumed energy load reduction. The PV's provide a standard comparative economic impact assessment for resource options other than DSM/SSE, but do not assess DSM/SSE program options.

• **Forecast LCOE Assessment of Non-Diesel Portfolio Costs:** Forecast LCOE are provided separately for the non-diesel resource option package in each Portfolio where relevant in order to compare overall life cycle present value costs (i.e., includes costs beyond 2030 as required) for

[137] As of October 14, 2011, NYMEX futures (light sweet crude) showed a price of $88.01 per bbl $US for 2012 and $92.55 per bbl US$ for December 2018. Based on the then current value of the Canadian dollar (0.9855 US$/CAN$), and allowance for processing and transport ($40c/litre in 2011$), the equivalent diesel price forecast in Whitehorse, Yukon for YEC would equal $0.97 per litre in 2012, $1.01 per litre in 2015, and $1.05 per litre in 2018. Assuming 2% inflation per year, the equivalent 2010$ fuel price would be $0.92/litre for this NYMEX-based 2015 fuel price and $0.90 per litre for the 2018 NYMEX-base price. In contrast, escalating the 2011 Resource Plan diesel price [2010$, based on YEC's 2009 GRA approved prices at Whitehorse] of 96c/litre by 2% per year would result in a 2012 price of $1.00 per litre, a 2015 price of $1.06 per litre and a 2018 price of $1.12 per litre. As reviewed in Appendix E, Attachment E2, NYMEX futures-based diesel fuel prices projected on the same basis for Whitehorse in early April 2011 [based on the then crude oil prices and value of the Canadian dollar] were higher than in October 2011 (i.e., about $1.10 per litre in 2014 through to 2019).

the specific resource option package. The diesel default resource option cost for fuel and O&M costs (2010$ at approximate 28 cents/kW.h) is assumed for comparison[138].

Present Value Costs

Table 4-2 provides for the 20-year planning period (2011-2030) the detailed PV analysis for the Default Diesel portfolio for each Resource Plan load scenario: Base Case, Scenario A and Scenario B. The Total PV Cost (millions$) for the Default Diesel portfolio is based on the sum of the PV Energy costs and the PV Capacity costs.

The Default Diesel portfolio option meets the forecast energy and capacity requirements for the grid over the planning period, relying on diesel generation and capacity to supply any shortfalls. The PV assessment for each portfolio option discounts costs at 6.56% per year, reflecting YEC's last approved blended cost of capital (i.e., to the extent that YEC's future approved cost of capital is higher than 6.56% the current PV assessment understates PV costs for capital intensive resource options relative to non-capital intensive resource options).

Generally, as noted in Table 4-2, for each resource option portfolio the following are included in the PV assessment:

- **PV Energy Costs:** Present value energy costs include all annualized costs (depreciation, return, fuel and O&M costs by year of operation) over the planning period for new non-diesel resource options included in a portfolio option plus diesel fuel and O&M costs for all energy supplied by diesel generation. Non-diesel resource option residual asset values that remain after 2030 are not addressed.
    - For the Default Diesel Portfolio, this is the PV of the total diesel generation fuel and O&M costs over the life of the project (discounted back to 2010$), and assumes a 50/50 blended cost based on use of existing and new diesel units[139].
- **PV Capacity Costs:** The present value capacity costs includes the full capital costs for new diesel capacity needed to meet capacity reliability requirements (i.e., diesel capacity additions

[138] This ignores diesel capacity capital costs. As noted, diesel plant capacity costs are very low relative to other resource options and YEC also can utilize existing diesel capacity throughout most of the planning period. Diesel capacity costs are fully considered in the PV analysis - excluding these costs from the Forecast LCOE analysis is done to simplify the analysis.

[139] Average diesel fuel and O&M cost of 28.03 cents/kW.h based on average of diesel fuel cost for existing units (30 cents/kW.h) and diesel fuel and O&M costs for new units (26.06 cents/kW.h) escalated annually by 2%.

needed to deal with retirements and/or load growth impacts on N-1 or LOLE capacity planning criteria). This includes all capital costs when the capacity is projected to be required, i.e., it does not address only annualized costs over the planning period. For non-diesel resource options, diesel capacity requirements are deferred or removed from the planning period as appropriate (i.e., to reflect firm capacity provided by a non-diesel resource option), and the portfolio is thereby credited with appropriate PV diesel capacity cost savings.

  - For the Default Diesel Portfolio, this includes the PV (2010$) of capital costs assumed for LOLE related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements (depending on which planning criteria takes precedence) – assuming diesel replacements occur at $1.5 million/MW with annual 2% inflation where there are forecast capacity shortfalls.
  - Based on capacity shortfall forecasts, during the 20-year planning period 60.4 MW of new diesel capacity is required under the no DSM/SSE case, and 37.1 MW of new diesel capacity is required with assumed DSM/SSE (i.e., this overall 20-year requirement is not affected by the different load scenarios). This is because all three load scenarios assume mine closures after 2021 and adopt the same non-industrial load forecast through the planning period.
  - Variation in capacity PV between load scenarios in Table 4-2 reflects the impact of projected mine loads in accelerating the timing of new capacity additions during the planning period (as a result of the LOLE capacity planning criteria requirements).

- **DSM/SSE Impacts:** The analysis shows present values with and without the assumed DSM/SSE to facilitate assessment of the extent to which uncertainty regarding the assumed DSM/SSE may affect the conclusions.

Table 4-2 shows PV costs (2010$) for the Default Diesel Portfolio increasing with higher forecast loads, and decreasing as a result of the assumed DSM/SSE. PV Energy costs are dominant (i.e., PV Capacity costs account for only 14-17% of total PV costs for all load scenarios other than the Base Case with DSM/SSE), where PV Energy costs are very low.

Table 4-2: Default Diesel Portfolio Option Present Value Grid Costs (2010$million): 2011-2030

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost[4]	Total PV Costs
No DSM/SSE				
Base Case	111.8	52.8		164.6
Scenario A	227.6	55.9		283.5
Scenario B	304.6	59.1		363.7
With DSM/SSE				
Base Case	30.8	31.9	35.4	98.1
Scenario A	133.9	34.7	35.4	204.0
Scenario B	207.3	38.4	35.4	281.2

Notes:
1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Diesel fuel O&M - assumes 50/50 blend of existing and new units.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement.
4. DSM/SSE average annual costs assumed at 7.5 cents/kW.h.

The above Default Diesel portfolio includes the impacts/effects of an assumed robust DSM/SSE programs (i.e., effect of DSM/SSE saving of diesel-related energy and capacity costs is approximately $80-$82 million under Scenario A or B). As noted, for this analysis DSM/SSE costs are assumed at 7.5 cents/ kW.h (2010$); in reality, DSM/SSE costs will vary depending on the types of DSM methods/programs (e.g., rates, subsidies, standards and costs) selected and the effectiveness of those choices in reaching their energy reduction targets. As Canadian jurisdictions typically assess DSM/SSE program cost effectiveness relative to total resource costs as well as rate impacts, DSM/SSE program costs are required to be competitive with costs of new generation and are often assessed to be well below costs for new generation[140]. Ongoing costs associated with DSM (e.g., O&M) generally include recurring or consistent program implementation costs, program evaluation costs and regulatory costs. Analysis regarding DSM/SSE costs and benefits is based on (and limited by) the best available information at this time (absent completion of the current conservation potential review and determination to proceed with specific DSM/SSE programs).

[140] This provides the utility with room to adjust for any uncertainty regarding the sustainability, costs and/or effectiveness of DSM energy reductions over the longer-term.

4.3 YUKON GREENHOUSE GAS EMISSIONS IMPACT

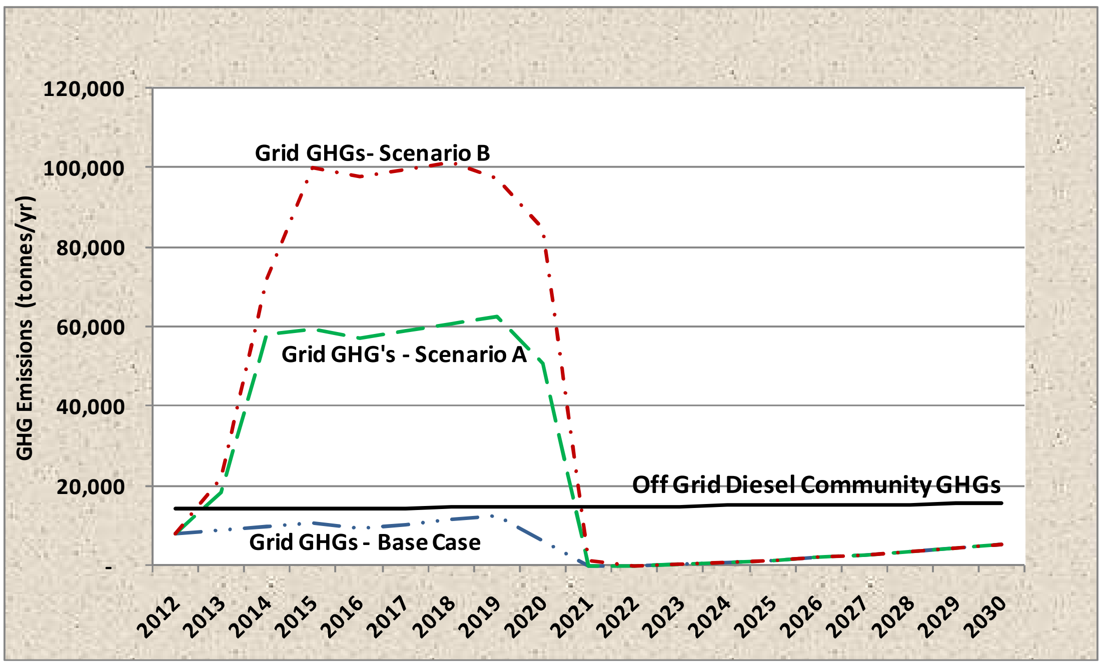
Increased diesel generation on or off the grid in Yukon will increase GHG emissions from power generation, with about 700 tonnes added GHG emissions per GW.h of diesel generation[141]. Annual levels of diesel generation (and related GHG emissions) vary a great deal under the Default Diesel Portfolio depending on the loads considered:

- **Grid Power Generation** – GHG emissions (tonnes/year) with the Default Diesel Portfolio vary as follows during the planning period for the different load scenarios with DSM/SSE.
  - **Base Case load:**
    - 2012-2020 – Vary from 6,100 to 12,400 tonnes/year
    - After 2020 –Vary from zero to 5,300 tonnes/year
  - **Scenario A load:**
    - 2012-2020 – Vary from 8,100 to 62,400 tonnes/year
    - After 2020 – Vary from zero to 5,300 tonnes/year
  - **Scenario B load:**
    - 2012-2020 – Vary from 8,100 to 101,300 tonnes/year
    - After 2020 – Vary from zero to 5,300 tonnes/year
- **Off-Grid Diesel Community Power Generation** – Over the past five years, off-grid communities served by YECL [Watson Lake, Beaver Creek, Destruction Bay, Swift River and Old Crow] have maintained diesel generation in a range between 20-22 GW.h/year (14,000 to 15,400 tonnes of GHGs per year). Minimal overall growth in off-grid utility generation is projected over the planning period. Under the Default Diesel Portfolio for the grid, these off-grid GHG emissions are not affected.
- **Off-Grid Industrial Power Generation** – As noted in Section 2, off-grid mines (at a distance that currently makes interconnection infeasible) are projected to develop using either on-site diesel or LNG, increasing potential overall Yukon GHG emissions by an additional 232,400 tonnes in 2015 and 749,800 tonnes by 2020. Under the Default Diesel Portfolio for the grid, these off-grid GHG emissions are not affected.

[141] As reviewed in Section 2, 700 tonnes GHG emissions per GW.h of diesel generation approximates the expected emissions with a new baseload unit under normal operating conditions (e.g., 4 kW.h/litre fuel use). Older diesel units or operating conditions with lower energy efficiencies will result in higher GHG emissions per GW.h.

Figure 4-3 below shows the total grid and off-grid utility power generation GHG emissions over the resource planning period with assumed DSM/SSE. Under Scenario A and Scenario B loads grid GHG emissions will exceed off-grid utility community GHGs over the period from 2012 through 2020. However, after 2021 minimal on grid GHG emissions are forecast compared to off-grid utility community GHG emissions in diesel rate zones. Overall grid and off-grid Yukon GHG emissions from power generation are expected to be much higher than the emissions shown in Figure 4-3 (i.e., off-grid industrial GHG emissions by 2015 and following may potentially be more than four times the Default Diesel grid emissions under Scenario A (see Figure 4-4)).

Figure 4-3: Grid & Off-Grid Diesel Community Power Generation GHG Emissions (tonnes/year) 2012-2030 with assumed DSM/SSE



Yukon Utility GHG Emissions	2012	2015	2020	2025	2030
Base Case	8,067	10,635	6,079	1,255	5,273
Scenario A	8,067	59,420	50,776	1,255	5,273
Scenario B	8,067	99,999	84,414	1,255	5,273
Off Grid Diesel Community GHGs	14,013	14,247	14,644	15,053	15,473

The above GHG emissions relate only to utility electricity generation (grid and off-grid diesel communities) and not total Yukon GHG emissions from all sources. The total Yukon wide estimate for GHG emissions in 2011 is approximately 375,000 tonnes (with total electrical sector GHGs in 2011 estimated to be 0% of this total (i.e., 1106 tonnes of a total 375,000 tonnes of emissions)).

As reviewed below, connecting mine loads in the near-term (rather than having these mines supplied off-grid with on-site diesel generation) will reduce GHG emissions even under the Default Diesel Portfolio to the extent that underutilized existing hydro generation can be used to reduce incremental diesel generation required for these incremental loads.

Considering 2015 forecast loads (with and without DSM/SSE), the following are noted with each grid load scenario regarding GHG emissions under the Default Diesel Portfolio[142]:

- **Base Case (with Minto and Alexco)** – Absent interconnection with the Yukon grid and considering 2015 forecast loads these mines would produce 44,100 tonnes of GHGs. With grid interconnection total grid GHG emissions are 10,640 tonnes with DSM/SSE and 16,590 tonnes without DSM/SSE. This equals between 27,510 and 33,460 tonnes of GHG emission savings in 2015 through these mines being interconnected.
- **Scenario A (Base Case with Victoria Gold)** – With interconnection of Victoria Gold, 2015 grid diesel requirements with and without DSM (including non-industrial loads losses) are 84.9 GW.h and 98.9 GW.h respectively. Total tonnes of GHG emissions with Victoria Gold connected to the grid are 59,430 tonnes with DSM/SSE and 69,230 tonnes without DSM/SSE; compared to the Base Case (same load excluding Victoria Gold), the added GHG emissions associated with the Victoria Gold load are 48,790 tonnes with DSM/SSE and 35,770 tonnes without DSM/SSE.
  - Absent an interconnection, the 95 GW.h of Victoria Gold load at site would be provided through diesel generation at site[143] (66,500 tonnes of GHG emissions off-grid if assume same diesel efficiency, slightly less if assume higher diesel unit efficiency).
  - In summary, if Victoria Gold comes into operation with the loads as assumed, overall GHG emissions would be lower if Victoria Gold is connected to the grid versus supplied with off-grid power.
- **Scenario B (Scenario A with Carmacks Copper and Whitehorse Copper Tailings [WHCT])** – With interconnection diesel requirements (for Scenario B including non-industrial loads and losses) with and without DSM/SSE are 142.9 GW.h and 158.1 GW.h respectively. Total amount of GHGs with these mine loads connected to the grid are 100,030 tonnes with DSM/SSE

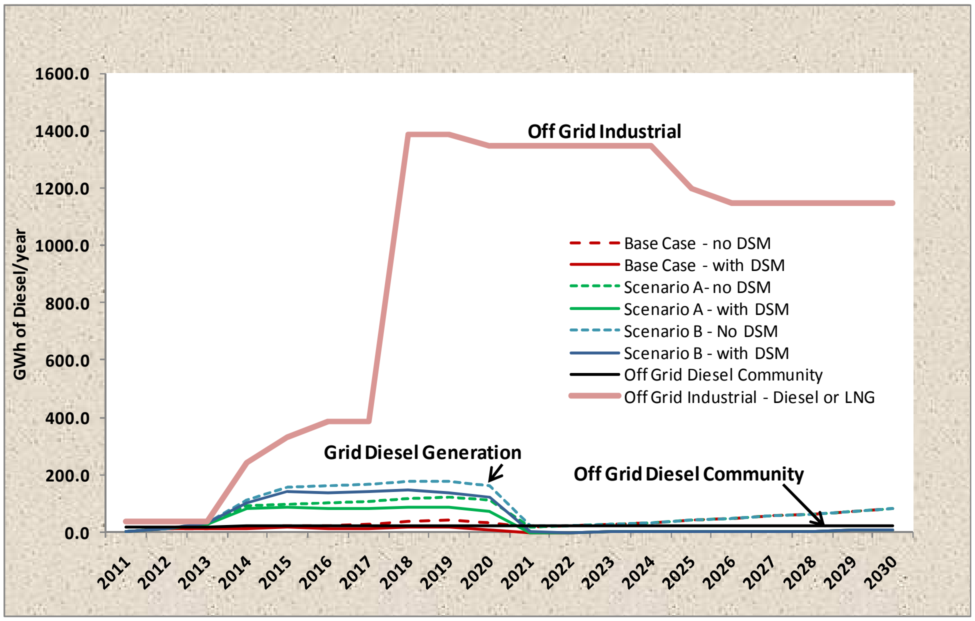
[142] Estimates provided below do not consider or reflect scenarios where a mine may have process heat requirement and use waste heat. The GHG emission analysis also focuses only on power generation impacts in Yukon, i.e., other GHG emissions from each sector for heat, transport or other activities are not addressed.
[143] Given the location of this mine north of the Keno area, non-diesel options such as LNG would likely be severely constrained by haul cost impacts.

and 110,670 tonnes without DSM/SSE. Added grid diesel generation impacts (and related GHG emissions) are linked mostly to the year round Victoria Gold and Carmacks Copper loads rather than the WHCT summer-only load.

In summary, if the Scenario A or B new industrial loads did not connect to the grid, diesel requirements on the grid and related grid GHG emissions would be reduced, as well as any related rate impacts to be shared by Yukon ratepayers. However, if these same potential industrial loads develop using on site diesel generation, overall Yukon GHG emissions under Scenario A and likely also Scenario B with off-grid diesel generation will be higher than would otherwise occur with the mine connected to the grid (reflecting the impact of grid access to available hydro generation during non-winter months as well at other times during years with above average flows).

Figure 4-4 and the accompanying table illustrate the extent to which GHG emissions from grid generation are a small portion of total GHG emission for the Yukon power generation sector. While utility cost considerations and ratepayer impacts are focused only on grid load default diesel generation requirements, considerations related to GHG emissions reductions in the power generation sector (whether utility generation or industrial on site generation) must consider the whole of Yukon.

Figure 4-4: Total Yukon Non-Renewable Generation (Grid & Off-Grid): 2011-2030



	2011	2015	2020	2025	2030
Grid Diesel Generation - Base Case					
GHG Emissions (tonnes) DSM/SSE	1,062	10,635	6,079	1,255	5,273
GHG Emissions (tonnes) - No DSM/SSE	1,062	16,588	22,773	28,220	57,979
Grid Diesel Generation - Scenario A					
GHG Emissions (tonnes) DSM/SSE	1,062	59,420	50,776	1,255	5,273
GHG Emissions (tonnes) - No DSM/SSE	1,062	69,228	78,400	28,220	57,979
Grid Diesel Generation - Scenario B					
GHG Emissions (tonnes) DSM/SSE	1,062	99,999	84,414	1,255	5,273
GHG Emissions (tonnes) - No DSM/SSE	1,062	110,673	114,304	28,220	57,979
Off Grid Utility Diesel Community Generation					
Off Grid Utility Diesel Generation (GWh)	19.9	20.4	20.9	21.5	22.1
GHG Emissions (tonnes)	13,936	14,247	14,644	15,053	15,473
Off Grid Mine Diesel Generation					
Diesel or LNG Generation (GW.h)	37.0	332.0	1537.8	1389.8	1337.8
GHG Emissions (tonnes)	25,900	232,400	749,814	646,214	609,814
(assumes LNG at Casino with combined cycle power generation)					

4.4 LONG-TERM DEVELOPMENT CONSIDERATIONS

The Default Diesel Portfolio is not normally viewed as conducive to expanded grid development.

As noted in the 2006 Resource Plan, it may not be considered feasible to develop new transmission to service a mine (with associated transmission line losses) if the power is being largely generated via diesel at Whitehorse, when the same power could likely be generated at the mine site using diesel without the associated transmission losses. To the extent that a new mine load such as Victoria Gold is in fact supplied by diesel generation under the Default Diesel Portfolio (rather than surplus hydro or other lower cost new supply options), the option of on-site diesel generation would serve to minimize the resulting Yukon diesel generation requirement due to lower line losses leading to lower diesel generation-related GHG emissions.

The above GHG emission analysis indicates that, at least under Scenario A, the connection of Victoria Gold to the grid would result in some diesel generation savings with the Default Diesel Portfolio relative to the option of diesel generation at the mine site. However, given the Charrette challenge to balance considerations of environment and cost, there is a continuing requirement to find ways to supply new mine loads with other "greener" grid generation supply options that can justify further grid connections and work to lower costs in both the near-term and longer-term.

Over the longer-term, load opportunities affecting longer-term legacy planning for new generation to start construction before 2021 remain highly uncertain and there are currently no assumed further grid connections in the forecast.

- The existing and currently committed grid system capability is forecast between 2021 and 2030 to require generation for non-industrial loads, under long-term average water year conditions, ranging from 8 to 83 GW.h/year (with and without DSM/SSE)[144].
- Aside from expected DSM/SSE activities during the planning period, these forecast diesel requirements will also be reduced by any near-term resource supply developments such as Marsh Lake Storage.
- Potential non-industrial sector electrification impacts to increase generation requirements are highly uncertain today, and unlikely to have major impacts within the planning period.

The Default Diesel Portfolio could potentially be viewed in the near-term as a flexible approach to accommodate the above uncertainties during a period when forecast grid loads do not easily facilitate major new renewable generation resource development (see Section 5.4).

[144] However, there are obvious risks regarding the long-term sustainability of ongoing DSM/SSE reductions as assumed beyond the next 10 to 20 years, and the two projections (with and without DSM/SSE) might be viewed as an indication of forecast uncertainties.

However, on its own, the Default Diesel Portfolio approach would increase the pressure to constrain all other utility costs to the extent that either Scenario A or Scenario B forecast loads materialize:

- As reviewed, the Default Diesel Portfolio under Scenario A or B would result in very large rate increase pressures by 2014-15, with or without DSM/SSE. These rate increase impacts would be over and above those otherwise required to recover ongoing cost increases, cost deferrals that need to be brought into rates, or other rate changes directed by the YUB.
- During periods of material diesel generation requirement (i.e., under Scenario A and Scenario B load scenarios), these fuel-related cost increases will act to place added pressure to constrain other O&M and capital cost items that would exacerbate material diesel-related rate increase impacts on ratepayers throughout Yukon. These pressures combined with uncertainty about longer-term loads could materially constrain ongoing capital spending and planning costs on other long-term resource planning options such as legacy greenfield hydro projects that could help in future to reduce both costs and emissions.
- The Default Diesel scenario would increase pressures to constrain connection of new loads to the grid in order to reduce overall near-term diesel requirements. Absent existing and potential future industrial connections to the grid; however, there would be little if any basis to pursue spending and planning costs related to other long-term resource planning options (i.e., without new industrial connected loads, the increased grid loads required to support new legacy resource developments would not be forecast during the current 20-year planning period).

5.0 MINIMUM GREENHOUSE GAS EMISSIONS PORTFOLIO OPTIONS

5.1 DEFINING THE PORTFOLIO OPTIONS

Portfolio options to yield minimum GHG emissions are examined below to address the near-term and longer-term load scenarios, assuming the same DSM/SSE as included with the Default Diesel Portfolio. These options focus primarily on potential renewable resource development responses to the forecast increase in energy and capacity as one path to avoid reliance on default diesel generation, based on hydro enhancement, wind and thermal-biomass or waste-to-energy (WTE) resource options as screened in Section 3.2.

Each of the eligible resource options is intended to minimize GHG emissions as compared to diesel generation. Each option is also constrained by a potential earliest in-service timing, potential level of generation throughout the year at full utilization, estimated costs, and other distinctive features. Finally, each option is capital intensive relative to diesel generation and therefore Forecast LCOE over its economic life is sensitive to forecast utilization levels over the 20-year resource planning period.

5.1.1 Available Near-Term Resource Options

Available near-term renewable resource options for the minimum GHG portfolio are summarized as follows based on the screening in Section 3.2:

- **Hydro Enhancements** – Marsh Lake Storage is assumed to be a likely option to be developed, while Gladstone Diversion is considered to be more problematic due to regulatory risks:
    - **Marsh Lake Storage –** This is a relatively small project. Earliest in-service is assumed in late 2014[145] (first full year 2015) at capital cost (2010$) of $10.5 million; annual generation of 6.4 GW.h on average, focused in winter months at current Whitehorse plant; annual operating cost (2010$) of $8/MW.h. Full Utilization LCOE (2010$) at 8.5 cents/ kW.h. Marsh Lake Storage is assumed to provide 1 MW of added reliable peak winter capacity.
    - **Gladstone in combination with Marsh Lake** – Consideration is given to Gladstone Diversion being developed as soon as feasible after Marsh Lake Storage in order to secure greatly increased hydro enhancement benefits. Earliest in-service for Gladstone

[145] Reflects time needed for YESAA, FAA and other permit processes and YWB licensing plus one construction season.

Diversion is assumed in late 2017[146] (first full year 2018) at capital cost (2010$) of $40 million; annual Gladstone Diversion generation of 36.6 GW.h on average, focused in winter months at current Aishihik plant; Gladstone Diversion annual operating cost (2010$) of $6/MW.h. Full Utilization LCOE (2010$) at 5.7 cents/kW.h. The combined Marsh Lake and Gladstone option Full Utilization LCOE (2010$) is 6.2 cents/kW.h. Gladstone Diversion is considered solely on the basis of potential diesel energy displacement benefits[147].

- **Thermal-Wood Biomass** - Two sets of wood-biomass thermal plant options are considered for in-service by late 2014[148] (2015 first full year of operation) with an assumed economic life of 20 years (reflects anticipated forest license tenure) - based on the assumed locations, full winter peak capacity benefits are assumed for each wood biomass plant option:
    - **25 MW plant located in Whitehorse:** This plant is assumed to have a capital cost (2010$) of $4.56 million per MW ($114 million), annual non-fuel operating cost of $4 million (2010$), and annual generation of 199.3 GW.h/year (91% annual capacity factor) using 139,510 tonnes (oven dry tonnes or "ODT") of wood biomass feedstock delivered from Haines Junction, the Fox Lake burn area and the Minto burn area at an average delivered cost (2010$) of $150/ODT ($105/MW.h). Full Utilization LCOE (2010$) for the 25 MW wood biomass option is 16.6 cents/kW.h; including $1.53 million of annual district heat revenues (per Morrison Hershfield estimates) reduces the Full Utilization LCOE to 15.8 cents/kW.h.
    - **10-15 MW plant located in the Minto burn area:** These plant options are smaller than the reported optimum scale for a biomass plant of 20-30+ MW, and therefore are assumed to incur greatly increased non-fuel costs per unit of output (i.e., capital cost (2010$) of $6.38 million per MW ($63.8 million) for the 10 MW plant and $5.7 million per MW ($85.5 million) for the 15 MW plant); the same annual non-fuel operating cost of $4 million (2010$) is assumed for each plant. Annual generation at 91% annual capacity factor (79.8 GW.h/year for 10 MW plant, 119.6 GW.h/year for 15 MW plant), with wood

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[146] Reflects time needed for YESAA, FAA and other permit processes and YWB licensing plus two construction seasons; the YESAA and FAA applications are assumed to be delayed due to need for up to two years of further pathogen studies required by DFO and delays until YEC can resolve arrangements with the local First Nation.
[147] No peak winter capacity benefit is assumed for Gladstone Diversion given that all generation impacts occur at Aishihik and under the N-1 test no reliable capacity currently exists at this plant.
[148] Assumed timing only for purposes of this analysis, and further prefeasibility analysis required to assess feedstock supply and required forestry licence requirements, as well as timing requirements for feasibility studies, YESAB review and other permitting, and construction.

biomass requirements at 0.7 ODT/MW.h. At these smaller plant scales, wood biomass feedstock costs are minimized by locating the plant in the wood supply area – and, based on current feedstock supply estimates, the only such location that could meet this test on a least cost basis is the Minto burn area near the Klondike Highway[149]. Wood biomass feedstock cost (2010$) is estimated at $96/ODT for a 10 MW plant and $104/ODT for a 15 MW plant. Full Utilization LCOE (2010$) is 17.5 cents/kW.h for the 10 MW plant and 15.8 cents/kW.h for the 15 MW plant.

- **Thermal - Municipal Solid Waste (MSW) or "Waste to Energy" (WTE)** – A 2.2 MW plant in Whitehorse and generating 17.1 GW.h/year (89% annual capacity factor) for a 25 year life is assumed in-service by late 2014[150] (2015 first full year) using 25,000 ODT/year of MSW feedstock plus a small amount of wood biomass (3,800 ODT/year at an assumed cost of $75/ODT), and with district heat net revenues, tipping fees and other revenues of $3.3 million/year (2010$); O&M costs excluding wood biomass of $2.7 million/year (2010$); and capital cost (2010$) of $17.73 million per MW ($39.0 million). Full Utilization LCOE (2010$) is 13.5 cents/kW.h with the assumed other revenues (23.7 cents/ kW.h with no district heat revenues, 31.4 cents/kW.h with no tipping fees or district heat revenues). Full winter peak capacity benefits are assumed for this plant.

- **Wind** – Two wind options are being considered, each with an earliest in-service in late 2014[151] (first full year 2015) and an assumed operating life of 25 years (the 10.5 MW option would be considered as a first stage of the 21 MW development):

  - **A 21 MW wind farm** is assumed at Ferry Hill (immediately north of Stewart Crossing), with a 5 MW DRUPS included for grid reliability requirements and added capital cost of $10 million (see Section 3.1 for explanation of this screening). Capital cost (2010$) of

[149] See Appendix E, Attachment E4 and the review therein of the Morrison Hershfield report. Haines Junction does not appear to have adequate biomass supply to sustain a 10 or 15 MW plant, whereas the Minto burn area alone could apparently sustain a 10 MW plant and, with some added feedstock from the Fox Lake burn area, a 15 MW plant. Wood feedstock costs for a Whitehorse plant reflect haul costs and are estimated (2010$) at $131/ODT for a 10 MW plant and $138/ODT for a 15 MW plant. If district heat revenue potentially available only at Whitehorse is treated as a feedstock cost offset, net feedstock costs for a Whitehorse location are estimated at $104/ODT for a 10 MW plant and $120/ODT for a 15 MW plant (i.e., costs that are in each instance higher than for the same scale plant located at the Minto burn area).

[150] Assumed timing only for purposes of this analysis, and further prefeasibility analysis required regarding feedstock supply and district heat sale arrangements, as well as timing requirements for feasibility studies, environmental review/permitting, and construction.

[151] An additional year of wind monitoring will be concluded at Ferry Hill site in spring 2012; following completion of satisfactory monitoring, three years are assumed to be required to come into service (one year for environmental review and approvals and two construction seasons).

$93.4 million (includes DRUPS and transmission connection to the Stewart Crossing south substation); annual average generation of 55.6 GW.h; annual operating cost (2010$) of $38/MW.h. Full Utilization LCOE (2010$) at 14.8 cents/kW.h. None of the plant's capacity would provide reliable peak winter capacity (beyond the 5 MW assumed DRUPS facility included in this option).

- **A 10.5 MW first stage development of the above Ferry Hill wind farm** is assumed without the need for any DRUPS[152] and with transmission connection only to Stewart Crossing north substation. Capital cost (2010$) of $49.552 million; annual average generation and operating cost at 50% of the 21 MW wind farm (27.8 GW.h/year and $1.05 million/year). Full Utilization LCOE (2010$) at 15.5 cents/kW.h. None of the plant's capacity would provide reliable peak winter capacity.

5.1.2 Available Longer-Term Resource Options

Available long-term renewable resource options for the minimum GHG planning portfolio as identified in Section 3.2 consist primarily of greenfield hydro resource options potentially available to start construction before 2021, provided that sufficient site specific planning processes are sustained as required throughout the next five year period through 2015.

Hydro resource options provide renewable energy with low GHG emissions. Subject to adequate grid loads to sustain high utilization for 30+ years, there are 17 medium to large hydro options that also offer low costs per kW.h (i.e., below 15 cents/kW.h Full Utilization LCOE) plus additional small hydro sites with costs below 25 cents/kW.h. These are summarized in Table 5.1 below.

- **Medium (11-60 MW) & Large (>60 MW) Hydro Options:**
  - **Less than 10 cents/kW.h:** Nine sites or schemes are identified in Section 3.2 with estimated Full Utilization LCOE's (2009$) below 10 cents/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 (over 850 GW.h/year).
  - **10-15 cents/kW.h:** A further eight sites or schemes are identified with Full Utilization LCOE's between 10 and 15 cents/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).

[152] This assumes that no added DRUPS is required for reliability so long as the wind resource development is limited to this scale on the grid. it is assumed that approximately 5 MW of spinning reserve is currently available and that (regardless of wind resource use) about 10 MW of existing non-base loaded hydro units would be converted to synchronous condenser peaking units at a cost of approximately $0.5 million per unit (see Appendix E, Attachment E5).

- **Other:** A further two medium scale sites located north of the Watson Lake area are identified with Full Utilization LCOE's under 15 cents/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.

- **Small (<10 MW) Hydro Options:**
  - **Southern Lakes (20-23 cents/kW.h):** Section 3.2 identifies up to 70 GW.h/year potentially available small hydro in the Southern Lakes region at Moon Lake and Tutchi River or Tutchi (Windy Arm), with annual energy potential for each site approximating 30 to 39 GW.h/year with Full Utilization LCOE (including transmission to Yukon grid) at 20-23 cents/kW.h.
  - **Pine Creek Hydro at Atlin:** Section 3.2 also identifies potential transmission connection of the Yukon grid to the Taku River Tlingit owned Pine Creek Hydro Generating Station near Atlin, B.C. to take advantage of underutilized existing capacity plus undeveloped capability at the generating station[153]. Options identified here include a 3.5 MW option (utilize existing surplus hydro with a 2.2 MW expansion, annual potential of 23 GW.h) and an 8 MW option that includes the expanded existing plant plus a new 4 MW downstream plant with an overall annual load potential of 52 GW.h.

[153] Yukon Energy has engaged in very preliminary discussions with representatives of the First Nation Development Corporation and a mutual interest has been expressed to continue discussions.

Table 5-1: Summary of Potential Hydro Sites

		Installed Capacity (MW)	Annual Energy (GWh)	Capital Cost (Million $2009)	Levelized Cost (c/kWh)
Small Hydro Projects <10MW)					
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
Medium Hydro Projects (<60 MW)					
< 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[1] & Hoole	50.1	351.1	728.9	10.7
	Slate Rapids[1] (powerhouse at foot of dam	22.3	156.3	441.4	14.6
Other[2]	Middle Canyon	38.0	200	773.5***	20.0
	Upper Canyon	25.2	176.6	677.2***	19.8
Large Hydro Project (>60 mW)					
< 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.

Geothermal and clean coal resource options were also identified in Section 3.2 as other long-term options that might also provide in Yukon both low cost and low GHG emissions. For the reasons reviewed below, neither of these options is currently considered as available to start construction before 2021:

- **Geothermal** opportunities in Yukon have been subject to high level review in order to ascertain geologic and economic potential for development for heat and electricity production at the following locations: Haines Junction, Volcano Mountain, Whitehorse, McArthur, Nash Creek and Larson Creek. A preliminary resource assessment and prioritization of sites has been recently undertaken for Yukon Energy by Borealis Geopower. This assessment indicates that, while unconfirmed, there is clearly a material and significant potential at the sites identified. Whitehorse is identified as a site with highest priority ranking compared to other sites[154], with its main advantage being proximity to power infrastructure and markets. However, the report indicates that all sites have some level of exploration risk, and that the information collected to date is insufficient to substantiate a finding of the inferred geothermal resources at any of the six sites.

Future consideration of geothermal is dependent on successful exploration that defines appropriate opportunities close to the grid. Considerable costs would likely be required to carry out the necessary ongoing exploration and confirmation drilling to locate and then develop geothermal as a greenfield resource in Yukon. Funding for this type of development activity at the scale likely to be needed is not typical for a regulated utility such as Yukon Energy. Accordingly, the 2011 Resource Plan does not provide any specific major proposed activities for geothermal beyond monitoring of related activities in Yukon.

- **Clean coal** opportunities exist in Yukon close to the grid, subject to development of a cost-effective clean coal technology as well as proven and cost-effective small scale coal technology. Given that development of such technologies will likely depend on activities in other major jurisdictions, no Yukon-specific activities are identified in the 2011 Resource Plan regarding this option beyond ongoing monitoring of indigenous Yukon coal resource development as well as evolving clean and small scale coal technology in other jurisdictions.

5.1.3 Near-Term Portfolio Options

GHG emissions in Yukon power generation are linked directly to diesel generation. To provide a clear reference point, it is assumed for the "Minimum GHG Emissions Portfolio" that the objective "to minimize GHG emissions from power generation" is equivalent in Yukon today to minimizing diesel generation through reliance only on renewable resource options. Section 5 explores the implications of relying only on renewable resource options to displace 80% or more of the future default diesel generation forecast in Section 4 under each load scenario.

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[154] Estimates of potential capacity and cost per kW.h for the Whitehorse site ranged from 30-45 MW and 9.3 to 12.6 cents/kW.h. Other sites had lower potential capacity estimates and higher potential cost estimates (except for Larson Creek, located in the far southeast corner of Yukon, which had the same cost range as Whitehorse).

The current resource planning is focused only on preliminary assessments of possible portfolio options in order to obtain guidance as to preferred resource options to be pursued at this time. Based on the available renewable resource options, near-term portfolio options (i.e., combinations of the renewable resource options) are defined to minimize diesel generation under each grid load scenario during the 2015-2019 period when forecast grid diesel generation is currently expected to be highest (i.e., averaging (with DSM/SSE) about 15 GW.h/year under the Base Case load forecast, about 85 GW.h/year under the Scenario A load forecast, and about 142 GW.h/year under the Scenario B load forecast).

5.1.3.1 Base Case Portfolio Options

Given the available renewable resource options, Base Case loads are not sufficient to merit examination of any of the above renewable options other than the following:

- Marsh Lake Storage (which could displace 6 GW.h/year [about 40%] of the Base Case average diesel generation during 2015-2019 with DSM/SSE) – Forecast LCOE (2010$) of 12.1 cents/kW.h for Base Case with DSM/SSE.
- Gladstone Diversion[155] combined with Marsh Lake Storage could displace 16-17 GW.h/yr [about 100%] of the Base Case average diesel generation during 2018-2019 with DSM/SSE); however, the Gladstone Diversion is not assumed to be in-service until late 2017 – Forecast LCOE (2010$) of 15.2 cents/kW.h for Base Case with DSM/SSE.
- The 10.5 MW Wind option (which could displace 11-13 GW.h year [about 80%] of the Base Case average diesel generation during 2015-2019 with DSM/SSE) – Forecast LCOE (2010$) of 52.9 cents/kW.h for Base Case with DSM/SSE.
- The 2.2 MW WTE option (which could displace 7-8 GW.h year [about 50%] of the Base Case average diesel generation during 2015-2019 with DSM/SSE) – Forecast LCOE (2010$) of 44.7 cents/kW.h for Base Case with DSM/SSE.

[155] Gladstone Diversion provides more diesel displacement capability (maximum impact 35-38 GW.h/year) than is needed for the Base Case; however, this resource option offers much lower cost per kW.h (as well as lower capital cost) for Base Case loads than would occur with other non-WTE renewable options (wind or wood biomass) and it is therefore selected for assessment.

In summary, three Base Case portfolio options to minimize GHG emissions (each includes Marsh Lake Storage) are defined for further assessment:

- Min GHG Portfolio - Base Case #1 - Marsh Lake Storage & Gladstone Diversion [2015-19 diesel displacement with DSM/SSE: on average over 2015-2019: 62%; after 2017 when Gladstone assumed in-service, 95-97%].
- Min GHG Portfolio - Base Case #2 - Marsh Lake Storage & 10.5 MW Wind [2015-19 diesel displacement with DSM/SSE: on average over 2015-2019: 95%].
- Min GHG Portfolio- Base Case #3 - Marsh Lake Storage & 2.2 MW WTE [2015-19 diesel displacement with DSM/SSE: on average over 2015-2019: 68%].

A summary of the annual diesel displaced by Base Case Portfolio Options 1 to 3 with DSM/SSE is provided in Table 5-2A (Option BC #1), Table 5-3A (Option BC #2) and Table 5-4A (Option BC #3). Present Value Costs for each of these Minimum GHG Portfolio Options are provided in Tables 5-2B (Option BC #1), Table 5-3B (Option BC #2), and Table 5-4B (Option BC #3) - these costs are reviewed in Section 5.2.

Table 5-2A: Minimum GHG Emissions Portfolio Option BC #1 - Forecast Grid Diesel Generation Displaced by Load Scenario DSM/SSE, Marsh Lake Storage and Gladstone: 2011 -2030 (GW.h/year)

Forecast Years	Base case				Scenario A				Scenario B			
	with DSM		without DSM		with DSM		without DSM		with DSM		without DSM	
	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)
2011	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2012	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2013	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2014	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2015	5.3	35%	6.0	25%	6.4	7%	6.3	6%	6.6	5%	6.3	4%
2016	5.1	38%	6.1	24%	6.4	8%	6.3	6%	6.6	5%	6.3	4%
2017	5.3	36%	6.2	21%	6.4	8%	6.2	6%	6.6	5%	6.3	4%
2018	15.7	97%	25.3	71%	34.5	40%	36.4	31%	37.5	26%	38.6	22%
2019	16.7	95%	27.2	65%	34.7	39%	36.7	30%	37.3	27%	38.6	22%
2020	8.7	100%	24.2	74%	33.0	46%	36.2	32%	36.6	30%	38.2	23%
2021	0.0	0%	16.0	96%	0.0	0%	16.6	100%	2.0	100%	20.4	85%
2022	0.0	0%	19.2	89%	0.0	0%	19.2	89%	0.0	0%	19.2	89%
2023	0.3	100%	22.0	81%	0.3	100%	22.0	81%	0.3	100%	22.0	81%
2024	1.0	100%	24.6	73%	1.0	100%	24.6	73%	1.0	100%	24.6	73%
2025	1.8	100%	26.8	66%	1.8	100%	26.8	66%	1.8	100%	26.8	66%
2026	2.7	100%	28.8	60%	2.7	100%	28.8	60%	2.7	100%	28.8	60%
2027	3.7	100%	30.5	55%	3.7	100%	30.5	55%	3.7	100%	30.5	55%
2028	4.9	100%	31.9	50%	4.9	100%	31.9	50%	4.9	100%	31.9	50%
2029	6.1	100%	33.1	45%	6.1	100%	33.1	45%	6.1	100%	33.1	45%
2030	7.5	100%	34.1	41%	7.5	100%	34.1	41%	7.5	100%	34.1	41%

Table 5-2B: Minimum GHG Emissions Portfolio Option BC #1 Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy)[4]
No DSM/SSE					
Base Case	83.9	51.6		135.5	-29.1
Scenario A	193.4	54.6		248.0	-35.5
Scenario B	268.5	57.8		326.3	-37.4
With DSM/SSE					
Base Case	43.8	30.8	35.4	110.0	11.9
Scenario A	134.6	33.5	35.4	203.5	-0.5
Scenario B	205.8	37.2	35.4	278.4	-2.7

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Marsh Lake & Gladstone costs. Assumes diesel fuel & O&M units for all diesel not displaced by Project.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Portfolio Option Present Value Costs.

Table 5-3A: Minimum GHG Emissions Portfolio Option BC #2 - Forecast Grid Diesel Generation Displaced by Load Scenario DSM/SSE, Marsh Lake Storage and 10.5 MW Wind: 2011 -2030 (GW.h/year)

Forecast Years	Base case				Scenario A				Scenario B			
	with DSM		without DSM		with DSM		without DSM		with DSM		without DSM	
	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)
2011	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2012	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2013	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2014	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2015	14.6	96%	19.3	82%	30.0	35%	31.8	32%	32.4	23%	32.8	21%
2016	13.0	97%	19.7	80%	29.5	36%	32.0	32%	32.3	23%	32.8	21%
2017	14.2	96%	21.3	71%	29.9	36%	32.6	30%	32.4	23%	32.8	20%
2018	15.3	95%	22.6	64%	30.2	35%	32.8	28%	32.5	22%	32.8	19%
2019	16.3	92%	23.6	57%	30.6	34%	32.3	26%	32.3	23%	32.8	19%
2020	8.7	100%	22.0	68%	28.1	39%	32.7	29%	32.6	27%	32.8	20%
2021	0.0	0%	15.6	94%	0.0	0%	15.6	94%	2.0	100%	19.4	81%
2022	0.0	0%	18.5	85%	0.0	0%	18.5	85%	0.0	0%	18.5	85%
2023	0.3	100%	20.6	75%	0.3	100%	20.6	75%	0.3	100%	20.6	75%
2024	1.0	100%	22.2	66%	1.0	100%	22.2	66%	1.0	100%	22.2	66%
2025	1.8	100%	23.4	58%	1.8	100%	23.4	58%	1.8	100%	23.4	58%
2026	2.7	100%	24.6	52%	2.7	100%	24.6	52%	2.7	100%	24.6	52%
2027	3.7	100%	25.7	46%	3.7	100%	25.7	46%	3.7	100%	25.7	46%
2028	4.9	100%	26.9	42%	4.9	100%	26.9	42%	4.9	100%	26.9	42%
2029	6.1	100%	28.2	39%	6.1	100%	28.2	39%	6.1	100%	28.2	39%
2030	7.5	100%	29.7	36%	7.5	100%	29.7	36%	7.5	100%	29.7	36%

Table 5-3B: Minimum GHG Emissions Portfolio Option BC #2 Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy)[4]
No DSM/SSE					
Base Case	106.1	51.6		157.8	-6.8
Scenario A	208.6	54.6		263.2	-20.3
Scenario B	284.4	57.8		342.2	-21.5
With DSM/SSE					
Base Case	63.8	30.8	35.4	130.0	31.9
Scenario A	147.4	33.5	35.4	216.3	12.3
Scenario B	217.3	37.2	35.4	289.9	8.7

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Marsh Lake and 10.5 MW Wind costs. Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Portfolio Option Present Value Costs.

Table 5-4A: Minimum GHG Emissions Portfolio Option BC #3 – Forecast Grid Diesel Generation Displaced by Load Scenario DSM/SSE, Marsh Lake Storage and 2.2 MW WTE: 2011 -2030 (GW.h/year)

Forecast Years	Base case				Scenario A				Scenario B			
	with DSM		without DSM		with DSM		without DSM		with DSM		without DSM	
	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)
2011	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2012	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2013	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2014	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2015	10.5	69%	12.9	54%	18.9	22%	19.5	20%	21.3	15%	21.9	14%
2016	9.8	73%	13.2	53%	18.7	23%	19.6	19%	21.2	15%	22.0	14%
2017	10.3	70%	14.2	47%	18.8	22%	19.9	18%	21.3	15%	22.2	13%
2018	10.8	67%	15.0	42%	18.9	22%	20.2	17%	21.4	15%	22.5	13%
2019	11.3	64%	15.8	38%	19.1	21%	20.6	17%	21.2	15%	22.5	13%
2020	7.5	87%	14.6	45%	18.2	25%	20.1	18%	20.4	17%	22.1	14%
2021	0.0	0%	10.9	66%	0.0	0%	10.9	66%	2.0	100%	13.0	54%
2022	0.0	0%	12.4	57%	0.0	0%	12.4	57%	0.0	0%	12.4	57%
2023	0.3	100%	13.7	50%	0.3	100%	13.7	50%	0.3	100%	13.7	50%
2024	1.0	100%	14.8	44%	1.0	100%	14.8	44%	1.0	100%	14.8	44%
2025	1.8	100%	15.7	39%	1.8	100%	15.7	39%	1.8	100%	15.7	39%
2026	2.7	100%	16.5	35%	2.7	100%	16.5	35%	2.7	100%	16.5	35%
2027	3.7	100%	17.1	31%	3.7	100%	17.1	31%	3.7	100%	17.1	31%
2028	4.8	99%	17.7	28%	4.8	99%	17.7	28%	4.8	99%	17.7	28%
2029	5.9	96%	18.3	25%	5.9	96%	18.3	25%	5.9	96%	18.3	25%
2030	6.8	91%	18.8	23%	6.8	91%	18.8	23%	6.8	91%	18.8	23%

1 **Table 5-4B: Minimum GHG Emissions Portfolio Option BC #3 Present Value Costs: 2011-2030 (2010$million)**

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy)[4]
No DSM/SSE					
Base Case	105.5	49.0		154.5	-10.1
Scenario A	214.4	51.8		266.2	-17.3
Scenario B	288.3	55.1		343.4	-20.3
With DSM/SSE					
Base Case	48.0	28.4	35.4	111.9	13.8
Scenario A	140.5	30.7	35.4	206.6	2.6
Scenario B	210.7	34.4	35.4	280.5	-0.6

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Marsh Lake and WTE costs. Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.

2 4. See Diesel Portfolio Option Present Value Costs.

5.1.3.2 Scenario A and B Portfolio Options

For Scenario A and B loads, higher levels of forecast default diesel use prior to 2021 provide opportunities for consideration of all currently available renewable resource projects.

The initial challenge is to review the short list of resource options (see Table 5-5) to assess which would be optimum to include in a near-term renewable resource portfolio to minimize GHG emissions under Scenario A and B loads.

Table 5-5: Diesel Displaced by Renewable Resource Option - 2015-2019
Percent of Potential Annual Diesel Displacement (%)

	Scenario A with DSM/SSE*	Scenario B with DSM/SSE**
25 MW Biomass Plant	100%	94%
15 MW Biomass Plant	85%	65%
10 MW Biomass Plant	64%	46%
Ferry Hill - Wind 21 MW	53%	36%
Ferry Hill - Wind 10.5 MW	28%	19%
Marsh Lake and Gladstone	21%	13%
2.2 MW WTE	16%	11%
Marsh Lake Storage	7%	5%

* Potential Annual Average Diesel Displacement = 85 GW.h/year
** Potential Annual Average Diesel Displacement = 142 GW.h/year

Table 5-5 summarizes diesel displacement capability (ranked by scale of displacement) for each eligible resource option as a percent of forecast default diesel average annual generation for Scenario A load and Scenario B load with DSM/SSE during the 2015-2019 period (85 and 142 GW.h/year respectively). This analysis is provided as an aid to screening of these options – when combinations of these resource options are considered, the combined diesel displacement impact will typically be less than the sum of the percentages shown below for each individual project.

The 25 MW thermal wood biomass plant is the only near-term renewable resource option that could potentially on its own achieve minimum GHG emissions for both Scenario A and B loads. As suggested earlier in Section 2 (Figure 2-13), a 25 MW wood biomass facility could displace 100% of Scenario A forecast diesel generation during the 2015-2019 period even if there was no DSM/SSE. Under Scenario B loads during this same period, a 25 MW wood biomass plant would displace 94% of forecast diesel generation with DSM/SSE and over 85% of forecast diesel generation with no DSM/SSE. This resource option would also make available waste heat for district heat sales in Whitehorse.

Aside from timing and other issues related to feedstock supply, the major problem with selecting a 25 MW wood biomass option for the minimum GHG emissions portfolio is the high cost incurred per kW.h of diesel displaced over the 20-year assumed life of the plant (see also Section 2.4 discussion of the challenges related to the 2011 Resource Plan load forecasts and diesel displacement opportunities on the Yukon hydro grid):

- Forecast LCOE (2010$) per kW.h of diesel displaced for the 25 MW wood biomass option is 92.5 cents/kW.h for Scenario A with DSM/SSE (42.2 cents/kW.h with no DSM/SSE); for Scenario B, Forecast LCOE remains high (60.5 cents/kW.h with DSM/SSE, and 35.4 cents/kW.h with no DSM/SSE). Including estimated district heat net revenues potentially available in Whitehorse would reduce these LCOE costs by only 2 to 4 cents/kW.h.
- This high cost per kW.h of diesel displaced in part reflects the extent to which a 25 MW plant operating year round during the 2015-2019 period (when mine loads are connected under Scenario A and B) would be in effect displacing a great deal of existing hydro generation over the summer/fall seasons. As shown earlier in Figure 2-13 for a 2015-2016 time period example under Scenario A with no DSM/SSE, on average the level of displaced hydro that is spilled (95.9 GW.h/year in the example) with this 25 MW wood biomass plant is almost as large as the diesel displaced (101 GW.h in the example), resulting in only about 51% of the wood biomass generation being used to displace diesel generation. This means that an annual cost in 2015 of 21 cents/kW.h with full utilization of all biomass plant generation to displace diesel (i.e., the full utilization costing assumed in Table 3-1, adjusted for the initial year of operation rather than overall life cycle average costs) would in reality become 41 cents/kW.h of diesel displaced in that year.
- However, this high cost for Forecast LCOE per kW.h of diesel displaced mostly reflects the sharp drop in forecast diesel generation after 2021. Forecast LCOE of 92.5 cents/kW.h of diesel displaced under Scenario A loads with DSM/SSE is greatly reduced (but still more expensive than diesel generation displaced) if forecast mine loads are extended by 5 to 10 years:
    - If assumed mine loads were to be extended sufficiently to maintain 89 GW.h/year of diesel displacement (the forecast displacement in 2019) to the end of 2025, Forecast LCOE would be lowered from 92.5 cents/kW.h to 55.4 cents/kW.h.
    - Extending the same level of diesel displacement to the end of 2030 would reduce Forecast LCOE to 42.8 cents/kW.h.

Figure 5-1 demonstrates why Forecast LCOE per kW.h of diesel displaced is increased so much for the 25 MW wood biomass plant under Scenario A loads with DSM/SSE. As shown, the option would generate

199 GW.h/year for 20 years; however, over its 20-year life, over 85% of this biomass energy would play no useful role in displacing diesel generation under Scenario A loads.

- When mine loads are on the grid (up to 2021), less than half of the biomass energy would be used to displace diesel generation - reflecting the extent to which a 25 MW thermal plant is far too large for the Yukon grid during this period.
- After 2021 (when no mine loads are assumed), the biomass energy from this plant would be used almost entirely to displace hydro from existing hydro facilities (a situation where the plant would presumably be closed to save feedstock and other O&M costs).
- In summary, the extent to which this 25 MW biomass plant over its life would in effect displace hydro generation (rather than diesel generation) is the main factor accounting for a Forecast LCOE of 92.5 cents/kW.h versus a Full Utilization LCOE of 16.6 cents/kW.h which assumes that all biomass generation fully used to displace diesel generation.

Figure 5-2 demonstrates the extent to which the 25 MW wood biomass plant Forecast LCOE at Scenario A load with DSM/SSE is materially higher than Forecast LCOE under the same load for the smaller 10 MW and 15 MW wood biomass plants that are able to secure much lower feedstock costs. This figure also shows for each biomass plant option the sensitivity of this Forecast LCOE under Scenario A load when mine loads are extended to 2025 and 2030. The smaller plants (10 MW and 15 MW) show broadly similar Forecast LCOE for Scenario A load with DSM/SSE and for each mine life sensitivity examined – Forecast LCOE for these smaller plants are roughly two-thirds of the Forecast LCOE for the 25 MW plant, but remain high, e.g. 29 cents/kW.h even under mine load Sensitivity #2 (mine life extended to 2030).

Based on the above information, the 25 MW wood biomass plant option is not considered further. Other renewable resource options (including the smaller wood biomass plants) are examined to select the most cost effective portfolio options to secure minimum GHG emissions (i.e., at least 80% diesel displacement during the 2015-2019 period. Ongoing work is refining optimum options where appropriate and feasible).

Looking at diesel displacement capability during 2015-2019, the 10 MW and 15 MW wood biomass options each displace more diesel than the wind, hydro or WTE resource options (see Table 5-5).

The 15 MW wood biomass plant on its own could displace over 80% of the potential diesel generation under Scenario A, and 65% under Scenario B.

In contrast, the percent of potential annual diesel displacement under Scenario A with DSM/SSE during 2015-2019 is 53% with the 21 MW wind option, 21% with the Marsh Lake & Gladstone combination option (reflects 5-year average - 40% diesel displacement by 2018 when Gladstone assumed in-service), 16% with the 2.2 MW WTE option, and 7% with Marsh Lake Storage option on its own.

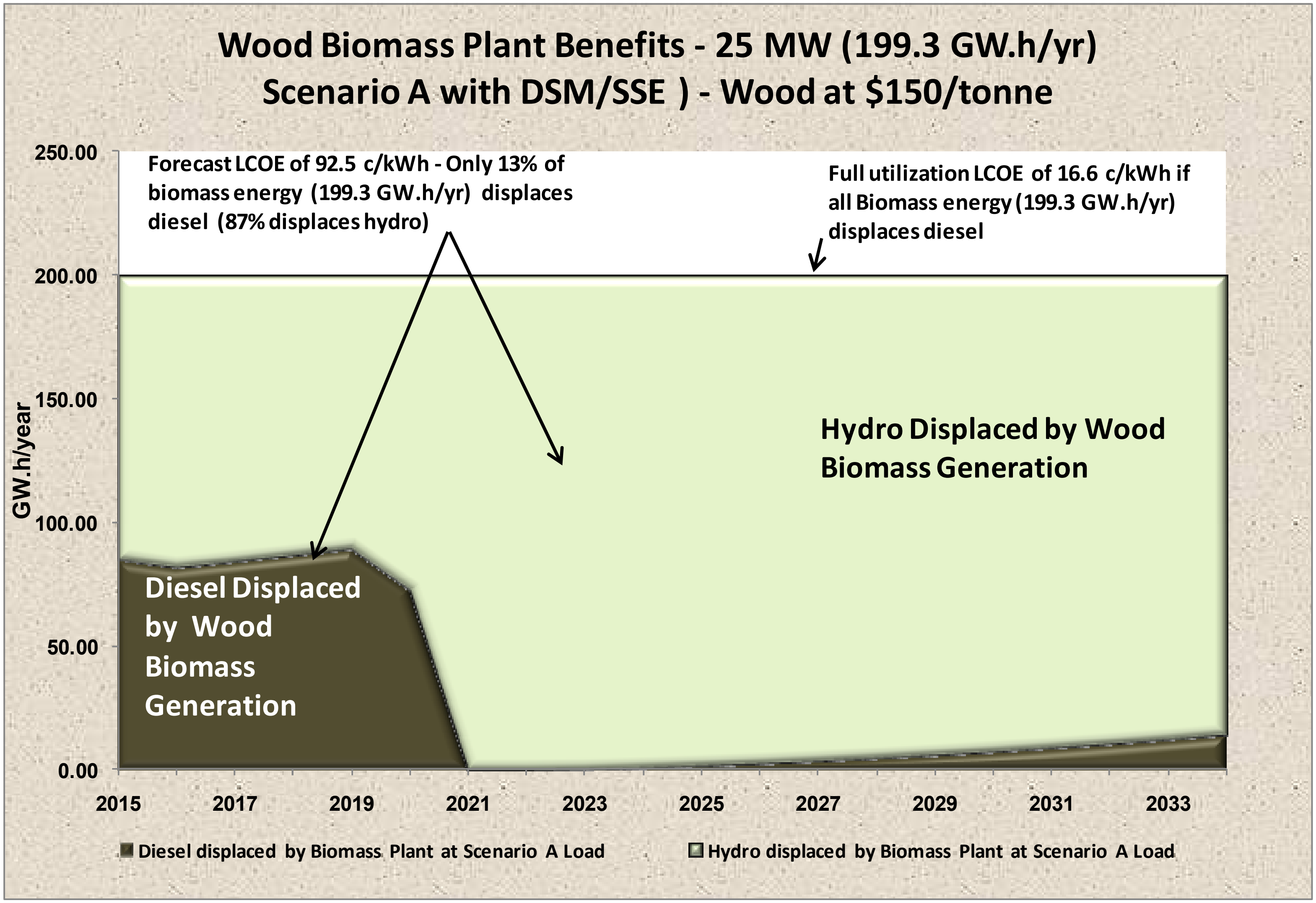
As noted in Section 2.4, developing new generation that cannot displace diesel generation would be wasteful – a factor which is demonstrated, for example, when explaining why long-term large hydro resource developments in Yukon (which offer local renewable supply with minimal GHG emissions) would not be economically feasible without first securing long-term diesel displacement loads to at least match the new hydro generation to be developed. The same principles that apply at an annual load level also apply at the seasonal load level, subject to the ability to facilitate enhanced hydro storage for use during the winter season.

The underlying economic feasibility issues noted here are not resolved by resort to secondary sales (interruptible sales) of the surplus hydro. The basic premise of secondary sales is that, at most, very limited investment is made to facilitate such sales, and that such sales are incidental to the project's primary objectives[156]. On a seasonal basis, secondary sales opportunities in Yukon are also weakest in summer (i.e., the season when diesel generation displacement opportunities are minimal). In summary, while secondary sales would continue to be promoted during periods of hydro surplus in order to reduce overall costs charged to firm service customers, such secondary sales cannot provide a sound economic rationale for planned developments that create surplus hydro on the grid.

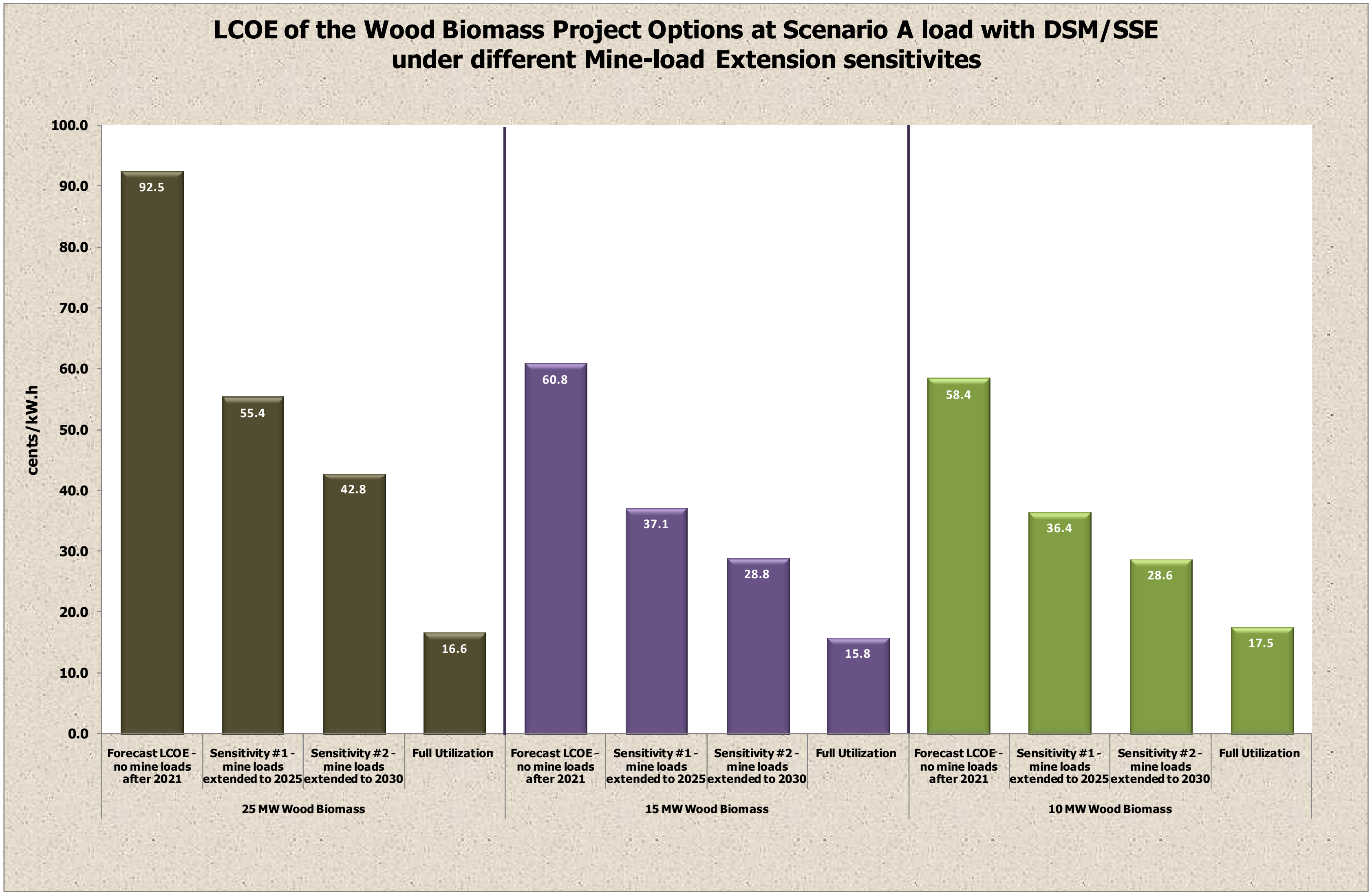
The concept of wood biomass thermal operation displacing generation from existing hydro resources, as discussed above, assumes that the wood biomass operation is not suspended at such times as hydro generation cannot be used (i.e., when water is spilled rather than used to run the generators). For the purpose of highlighting the challenges related to the existing hydro grid, this concept was retained in this analysis. However, where feasible, YEC would not in practice allow existing hydro generation to be displaced by other more costly sources of generation (i.e., the wood biomass plant, which (as a thermal option) can be shut down when so required, would not be operated in years (and perhaps during seasons) when its generation fails to displace material diesel generation). In the following analysis, options are noted when the wood biomass option has no O&M costs after the mine loads are shut down. This facilitates savings in ongoing operating and maintenance costs (but the annual capital costs continue to be included in the analysis).

[156] See response to YUB-YEC-1-44, YEC Mayo B Application for an Energy Project Certificate.

Figure 5-1: Wood Biomass 25 MW Thermal Project Displacing Diesel & Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021)



1 **Figure 5-2: Summary LCOE (2010$) for Thermal Wood Biomass Plant Options at Scenario A Load with DSM/SSE**



2

In defining minimum GHG emission portfolio options for Scenario A and B loads, it is relevant to examine whether certain renewable resource options merit consideration based simply on costs, notwithstanding less impact than wood biomass plant options in displacing diesel generation under Scenario A or B loads.

Figure 5-3 provides Forecast LCOE [2010$] at Scenario A load with DSM/SSE, and different sensitivity cases for extending mine load, for 15 MW wood biomass, 21 MW Wind, 10.5 MW Wind, 2.2 MW WTE, and Marsh Lake Storage combined with Gladstone Diversion. Figure 5-4 uses the 21 MW Wind option to demonstrate why Forecast LCOE per kW.h of diesel displaced increases so much for capital intensive options under Scenario A (i.e., over the 25 year life of the 21 MW Wind project, most of the 55.6 GW.h of annual average generation is forecast to play no useful role in displacing diesel generation under Scenario A loads with mine loads forecast not to extend beyond 2020). In differing ways, similar impacts occur for each of the other renewable resource options examined.

The following considerations are noted:

- Marsh Lake Storage is assumed to be included in any minimum GHG emissions portfolio option, reflecting its relatively low Forecast LCOE (e.g., 11.4 cents/kW.h under Scenario A with DSM/SSE) and expected development timing.
- Gladstone Diversion combined with Marsh Lake Storage offers low costs per kW.h similar to the Marsh Lake Storage alone option (Forecast LCOE 13.1 cents/kW.h under Scenario A with DSM/SSE), as well as much greater diesel displacement capability once Gladstone comes into service[157]; however, Gladstone Diversion's regulatory risk and delayed earliest in-service timing mean that it can be considered only as a possible added future development that likely cannot be under construction by 2015.
- The 21 MW and 10.5 MW Wind options reflect different development staging for an initial wind farm. Under Scenario A load with DSM/SSE, Forecast LCOE is 40 cents/kW.h for the 21 MW larger scale development and 34.7 cents/kW.h for the smaller first stage development option (i.e., costs per kW.h more than double costs for Marsh Lake and Gladstone).
    - These wind options offer notable diesel displacement with Forecast LCOE well below that shown for the 10 and 15 MW wood biomass plant options (as provided in Figure 5-2).

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[157] By 2018 the combined Gladstone and Marsh Lake projects would displace 40 % of Scenario A load with DSM/SSE, and 26% of Scenario B load with DSM/SSE.

  - Development of the 10.5 MW first stage wind option would facilitate further future development of this site's wind farm.

- The 2.2 WTE option Forecast LCOE of 31.5 cents/kW.h under Scenario A load with DSM/SSE[158] (including district heat revenues and tipping fees) does not offer either low cost or large scale diesel displacement. Figure 5-3 notes that the Forecast LCOE of 31.5 cents/kW.h under Scenario A reflects costs at 73.5 cents/kW.h before offset revenues for tipping fees (17.9 cents/kW.h) and district heat revenues (24.1 cents/kW.h – this revenue source is also potentially available for thermal generation options using other feedstock). The WTE resource option is considered further only for Scenario A and B loads as a potential "extra" renewable resource to secure greater GHG reduction.

In summary, four near-term Scenario A and B "min GHG" portfolio options are defined for further assessment. As reviewed below, Marsh Lake Storage is included in each portfolio option. The first two options compare combining Marsh Lake Storage with either a 15 MW wood biomass plant (which has ample capacity for the forecast loads) or a 21 MW wind project plus 2.2 MW WTE project. The second two options also include Gladstone Diversion (assuming that this project is permitted and in service by late 2017) and compare combining Marsh Lake Storage and Gladstone Diversion plus a 21 MW wind project with or without a 2.2 WTE project:

- **Min GHG Portfolio – Scenario A&B #1 (Marsh & Wood)** – Marsh Lake Storage & 15 MW Wood Biomass [2015-19 diesel displacement with DSM/SSE: 90% for Scenario A and 70% for Scenario B]; this portfolio optimizes the wood biomass resource option for Scenario A and B loads. GHG reduction target is achieved without the need to add further resource options.

- **Min GHG Portfolio – Scenario A&B #2 (Marsh, Wind & WTE)** – Marsh Lake Storage, 21 MW Wind, & 2.2 WTE [2015-19 diesel displacement with DSM/SSE: 72% for Scenario A and 50% for Scenario B]; this portfolio is the best GHG emission reduction available in the near-term from eligible renewable resource options without resort to wood biomass or Gladstone Diversion.

- **Min GHG Portfolio – Scenario A&B #3 (Marsh-Gladstone & Wind)** – Marsh Lake Storage & Gladstone Diversion, & 21 MW Wind [2015-19 diesel displacement with DSM/SSE: on average over 2015-2019: 70% for Scenario A and 49% for Scenario B; after 2017 when Gladstone

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[158] Forecast LCOE (2010$) for the 2.2 MW WTE option is 28.8 cents/kW.h for Scenario B with DSM/SSE; with no DSM/SSE, Forecast LCOE is 17.6 cents/kW.h for Scenario A and 16.8 cents/kW.h for Scenario B. Full Utilization LCOE is 13.5 cents/kW.h.

assumed in-service, 84% for Scenario A and 61% for Scenario B]; this portfolio shows the benefit without WTE if Gladstone Diversion is in service in 2018.

- **Min GHG Portfolio – Scenario A&B #4 (Marsh-Gladstone, Wind & WTE)** – Marsh Lake Storage & Gladstone Diversion, 21 MW Wind, & 2.2 MW WTE [2015-19 diesel displacement with DSM/SSE: on average over 2015-2019: 81% for Scenario A and 58% for Scenario B; after 2017 when Gladstone assumed in-service, 92% for Scenario A and 70% for Scenario B]; this portfolio represents the best GHG emission reduction available in the near-term from the eligible renewable resource options without resort to wood biomass.

A summary of the annual diesel displaced by Scenario A and B Portfolio Options #1 to #4 is provided in Table 5-6A (Option A/B #1), Table 5-7A (Option A/B), #2 Table 5-8A (Option A/B #3), and Table 5-9A (Option A/B #4). Present Value Costs for each of these Minimum GHG Portfolio Options are provided in Tables 5-6B (Option A/B #1), Table 5-7B (Option A/B #2), Table 5-8B (Option A/B #3) and Table 5-9B (Option A/B #4) - these present value costs are reviewed in Section 5.2.

Figure 5-3: Forecast LCOE (2010$) - 15 MW Wood Biomass, 21 MW Wind, 10.5 MW Wind, 2.2 MW WTE and Marsh Lake & Gladstone - Scenario A Load with DSM/SSE

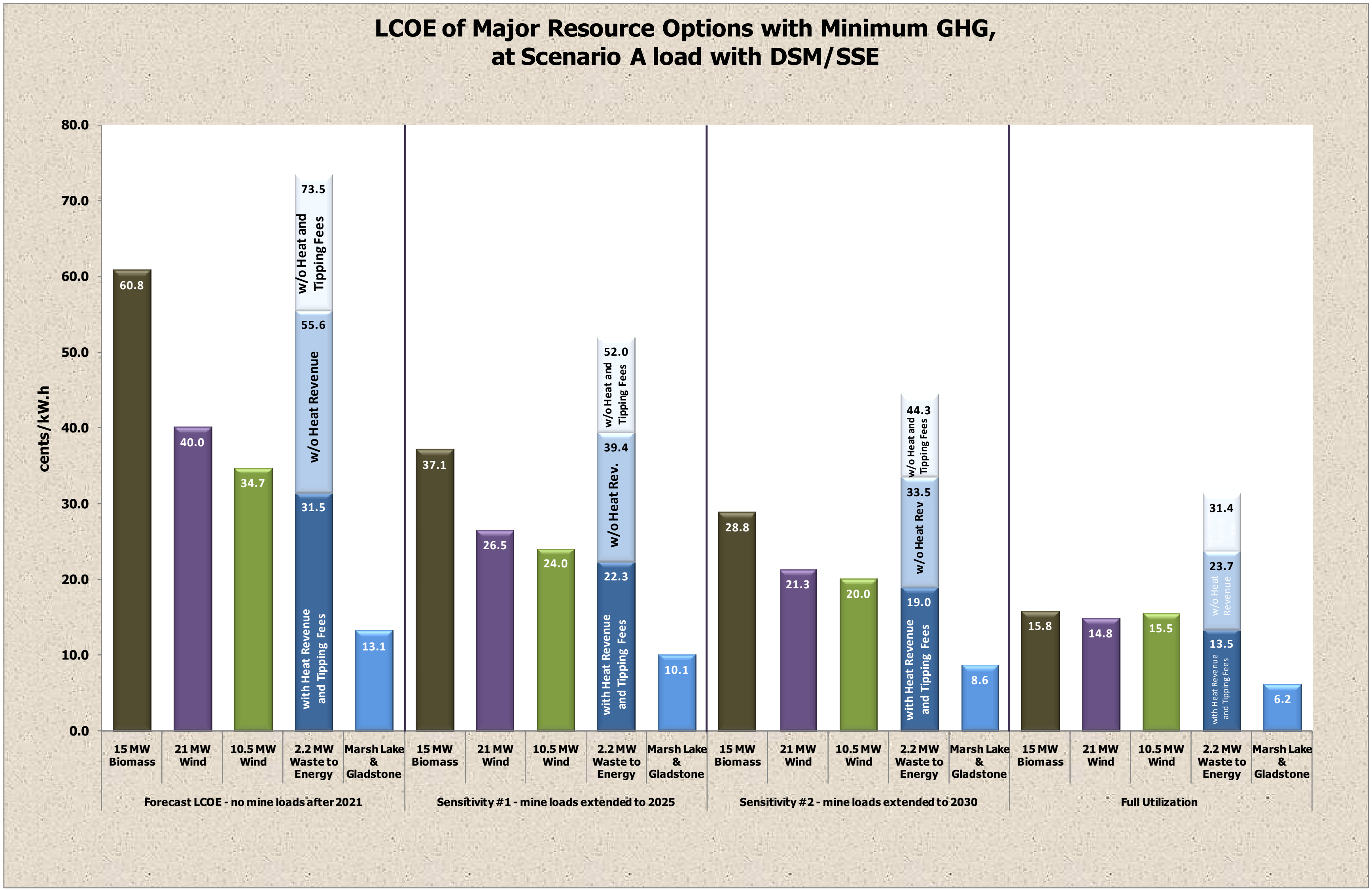


Figure 5-4: Wind Project: Displacing Diesel and Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021)

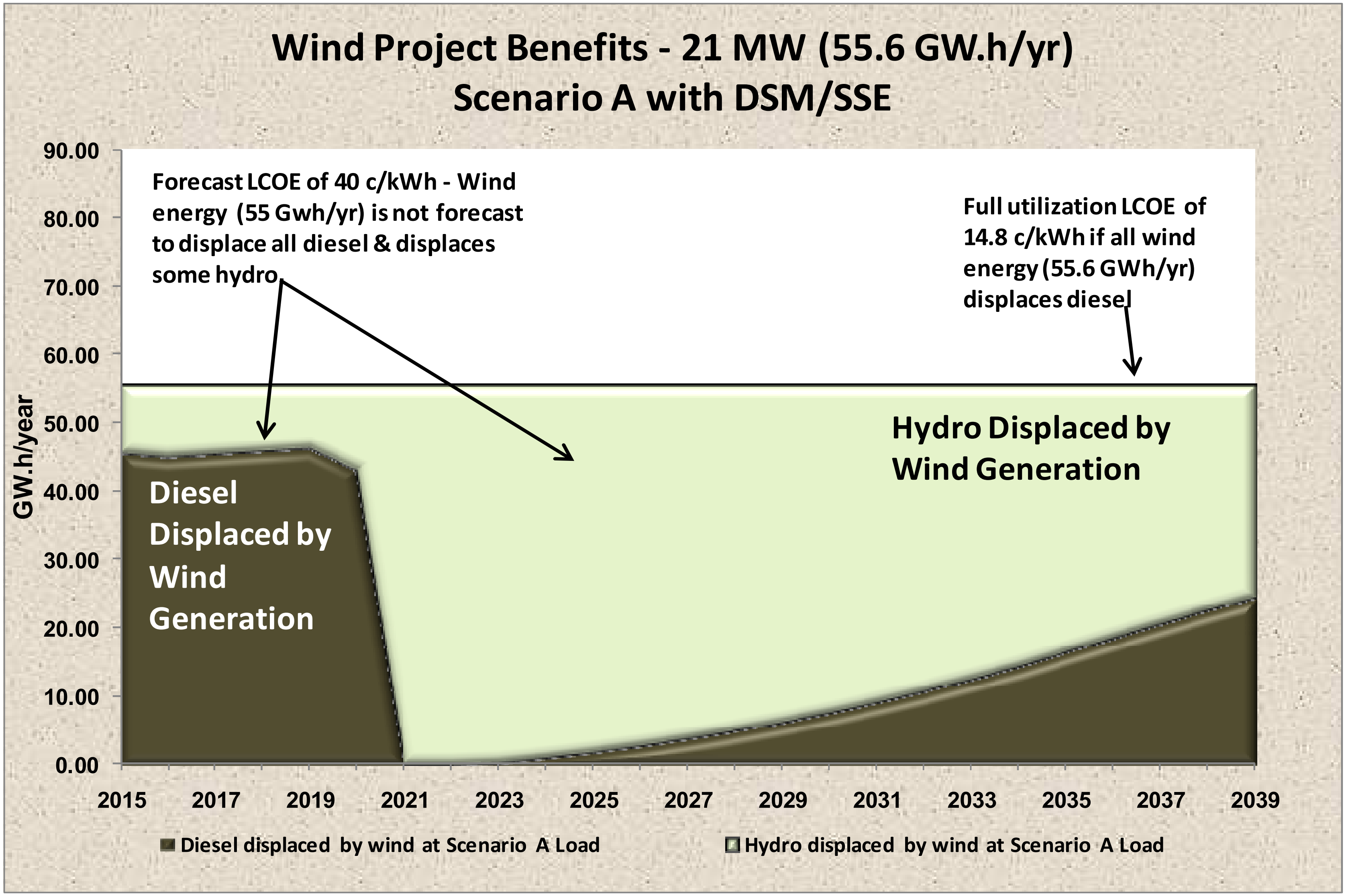


Table 5-6A: Minimum GHG Emissions Portfolio Option A/B #1 Forecast Grid Diesel Generation Displaced by Load Scenario DSM/SSE, Marsh Lake Storage & 15 MW Biomass: 2011-2030 (GW.h/year)

Forecast Years	Scenario A				Scenario B			
	with DSM		without DSM		with DSM		without DSM	
	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)
2011	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2012	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2013	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2014	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2015	76.7	90%	83.9	85%	98.7	69%	102.0	65%
2016	74.8	92%	84.7	84%	97.9	70%	102.3	64%
2017	76.2	91%	88.0	81%	98.5	69%	103.8	62%
2018	77.6	90%	91.0	78%	99.2	69%	105.3	60%
2019	79.0	89%	93.7	75%	97.8	70%	105.3	60%
2020	68.9	95%	89.5	80%	92.5	77%	103.0	63%
2021	0.0	0%	16.6	100%	2.0	100%	24.0	100%
2022	0.0	0%	21.6	100%	0.0	0%	21.6	100%
2023	0.3	100%	27.3	100%	0.3	100%	27.3	100%
2024	1.0	100%	33.5	100%	1.0	100%	33.5	100%
2025	1.8	100%	40.3	100%	1.8	100%	40.3	100%
2026	2.7	100%	47.7	100%	2.7	100%	47.7	100%
2027	3.7	100%	55.7	100%	3.7	100%	55.7	100%
2028	4.9	100%	62.7	98%	4.9	100%	62.7	98%
2029	6.1	100%	69.4	95%	6.1	100%	69.4	95%
2030	7.5	100%	75.5	91%	7.5	100%	75.5	91%

Table 5-6B: Minimum GHG Emissions Portfolio Option A/B #1 Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy)[4]
No DSM/SSE					
Scenario A	253.1	36.8		289.9	6.5
Scenario B	310.2	39.1		349.3	-14.4
With DSM/SSE					
Scenario A	232.2	16.5	35.4	284.1	80.0
Scenario B	278.7	18.5	35.4	332.6	51.4

Notes:
1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Assumes diesel fuel & O&M units for all diesel not displaced by renewable resources.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Portfolio Option Present Value Costs.

Table 5-7A: Minimum GHG Emissions Portfolio Option A/B #2 Forecast Grid Diesel Generation Displaced by Load ScenarioDSM/SSE, Marsh Lake Storage & 21 MW Wind and 2.2 MW WTE: 2011-2030 (GW.h/year)

Forecast Years	Scenario A				Scenario B			
	with DSM		without DSM		with DSM		without DSM	
	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)
2011	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2012	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2013	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2014	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2015	61.1	72%	64.7	65%	71.2	50%	72.4	46%
2016	60.2	74%	65.1	65%	70.9	51%	72.5	45%
2017	60.9	72%	66.6	62%	71.1	50%	72.9	43%
2018	61.6	71%	68.0	59%	71.4	49%	73.2	42%
2019	62.3	70%	69.2	56%	70.8	51%	73.2	42%
2020	57.2	79%	67.3	60%	68.6	57%	72.7	44%
2021	0.0	0%	16.6	100%	2.0	100%	24.0	100%
2022	0.0	0%	21.6	100%	0.0	0%	21.6	100%
2023	0.3	100%	27.3	100%	0.3	100%	27.3	100%
2024	1.0	100%	33.5	100%	1.0	100%	33.5	100%
2025	1.8	100%	40.3	100%	1.8	100%	40.3	100%
2026	2.7	100%	45.7	96%	2.7	100%	45.7	96%
2027	3.7	100%	50.0	90%	3.7	100%	50.0	90%
2028	4.9	100%	53.9	84%	4.9	100%	53.9	84%
2029	6.1	100%	57.4	78%	6.1	100%	57.4	78%
2030	7.5	100%	60.5	73%	7.5	100%	60.5	73%

Table 5-7B: Minimum GHG Emissions Portfolio Option A/B #2 Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy)[4]
No DSM/SSE					
Scenario A	212.2	45.7		257.9	-25.6
Scenario B	280.5	48.8		329.3	-34.4
With DSM/SSE					
Scenario A	178.0	24.6	35.4	238.0	34.0
Scenario B	238.7	28.1	35.4	302.3	21.1

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Marsh Lake, Wind and WTE costs. Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Portfolio Option Present Value Costs.

Table 5-8A: Minimum GHG Emissions Portfolio Option A/B # 3 Forecast Grid Diesel Generation Displaced by Load Scenario DSM/SSE, Marsh Lake Storage & Gladstone Diversion, 21 MW Wind: 2011-2030 (GW.h/year)

Forecast Years	Scenario A				Scenario B			
	with DSM		without DSM		with DSM		without DSM	
	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)
2011	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2012	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2013	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2014	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2015	50.7	60%	53.3	54%	57.4	40%	57.9	37%
2016	50.0	61%	53.5	53%	57.3	41%	58.0	36%
2017	50.5	60%	54.6	50%	57.4	40%	58.1	35%
2018	73.6	85%	83.0	71%	86.3	60%	88.3	50%
2019	74.8	84%	84.2	68%	85.8	62%	88.3	50%
2020	65.9	91%	82.2	73%	83.7	69%	87.5	54%
2021	0.0	0%	16.6	100%	2.0	100%	24.0	100%
2022	0.0	0%	21.6	100%	0.0	0%	21.6	100%
2023	0.3	100%	27.3	100%	0.3	100%	27.3	100%
2024	1.0	100%	33.5	100%	1.0	100%	33.5	100%
2025	1.8	100%	40.3	100%	1.8	100%	40.3	100%
2026	2.7	100%	47.7	100%	2.7	100%	47.7	100%
2027	3.7	100%	54.0	97%	3.7	100%	54.0	97%
2028	4.9	100%	60.5	94%	4.9	100%	60.5	94%
2029	6.1	100%	66.3	90%	6.1	100%	66.3	90%
2030	7.5	100%	71.6	86%	7.5	100%	71.6	86%

Table 5-8B: Minimum GHG Emissions Portfolio Option A/B # 3 Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy)[4]
No DSM/SSE					
Scenario A	202.1	48.3		250.5	-33.0
Scenario B	272.3	51.5		323.8	-39.8
With DSM/SSE					
Scenario A	173.3	27.3	35.4	236.0	32.0
Scenario B	234.0	30.9	35.4	300.4	19.2

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Assumes diesel fuel & O&M units for all diesel not displaced by renewable resources.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Option Present Value Costs.

Table 5-9A: Minimum GHG Emissions Portfolio Option A/B #4 Forecast Grid Diesel Generation Displaced by Load Scenario DSM/SSE, Marsh Lake Storage & Gladstone Diversion & 21 MW Wind and 2.2 MW WTE: 2011-2030 (GW.h/year)

Forecast Years	Scenario A				Scenario B			
	with DSM		without DSM		with DSM		without DSM	
	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)	(GW.h/y)	(%)
2011	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2012	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2013	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2014	0.0	0%	0.0	0%	0.0	0%	0.0	0%
2015	61.1	72%	64.7	65%	71.2	50%	72.4	46%
2016	60.2	74%	65.1	65%	70.9	51%	72.5	45%
2017	60.9	72%	66.6	62%	71.1	50%	72.9	43%
2018	80.2	93%	94.0	81%	100.1	69%	102.7	58%
2019	81.5	91%	96.6	78%	99.5	72%	102.6	58%
2020	72.5	100%	92.4	83%	95.5	79%	101.1	62%
2021	0.0	0%	16.6	100%	2.0	100%	24.0	100%
2022	0.0	0%	21.6	100%	0.0	0%	21.6	100%
2023	0.3	100%	27.3	100%	0.3	100%	27.3	100%
2024	1.0	100%	33.5	100%	1.0	100%	33.5	100%
2025	1.8	100%	40.3	100%	1.8	100%	40.3	100%
2026	2.7	100%	47.7	100%	2.7	100%	47.7	100%
2027	3.7	100%	55.7	100%	3.7	100%	55.7	100%
2028	4.9	100%	64.2	100%	4.9	100%	64.2	100%
2029	6.1	100%	73.2	100%	6.1	100%	73.2	100%
2030	7.5	100%	78.4	95%	7.5	100%	78.4	95%

Table 5-9B: Minimum GHG Emissions Portfolio Option A/B # 4 Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only[4]
No DSM/SSE					
Scenario A	211.8	45.7		257.5	-26.0
Scenario B	278.4	48.8		327.2	-36.5
With DSM/SSE					
Scenario A	188.7	24.6	35.4	248.8	44.8
Scenario B	243.6	28.1	35.4	307.2	26.0

Notes:
1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Marsh Lake&Gladstone, Wind and WTE costs. Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Portfolio Option Present Value Costs.

5.2 GRID ECONOMIC IMPACTS

As reviewed in Section 4.2, grid economic impacts for Portfolio Options are compared based on Forecast LCOE of non-diesel resource option package in each Portfolio and present value (PV) costs for each Portfolio. The following assessment focuses on the Minimum GHG Emissions Portfolio Options, looking separately in each instance at grid economic impacts for Base Case load options versus Scenario A and B load options (i.e., minimum GHG emissions reduction is very different for these different near-term load scenarios).

Forecast LCOE - Non-Diesel Portfolio Options

Forecast LCOE are provided in Table 5-10 (Base Case Load options) and Table 5-11 (Scenario A and B Load options) for the non-diesel resource option package in each Minimum GHG Emissions Portfolio Option in order to compare overall life cycle present value costs (i.e., includes costs beyond 2030 as required) for the specific resource option package. The diesel default resource option cost for fuel and O&M costs (2010$ at approximate 28 cents/kW.h) is assumed for comparison.

Except for the hydro enhancement portfolios (Marsh Lake Storage and Gladstone Diversion), Forecast LCOE for these Portfolio Options under loads with DSM/SSE at best approximate fuel and O&M costs for diesel. Options such as BC #2 and A/B #1, which minimize GHG emissions without relying on Gladstone Diversion, show forecast life cycle LCOE costs that are materially higher than diesel.

Table 5-10: Forecast LCOE (cents/kW.h in 2010$) for Minimum GHG Emissions Non-Diesel Portfolio Options (excludes diesel costs) – Base Case Load Options

	Diesel	Option BC #1 - Marsh Lake Storage & Gladstone Diversion	Option BC #2 - Marsh Lake Storage, & 10.5 MW Wind	Option BC #3 - Marsh Lake Storage and 2.2 MW WTE
No DSM/SSE				
Base Case	28.0	7.5	18.5	16.2
Scenario A	28.0	7.2	16.3	14.6
Scenario B	28.0	7.1	16.1	14.0
With DSM/SSE				
Base Case	28.0	15.2	42.2	31.7
Scenario A	28.0	13.1	28.9	24.2
Scenario B	28.0	12.8	27.3	22.5
Full Utilization	28.0	6.2	13.8	11.8

Table 5-11: Forecast LCOE (2010$) for Minimum GHG Emissions Non-Diesel Portfolio Options (excludes diesel costs) – Scenario A and B Load Options

	Diesel	Option A/B #1 - Marsh Lake Storage and 15 MW Biomass	Option A/B #1 - Marsh Lake Storage and 15 MW Biomass (No O&M after 2020)	Option A/B #2 - Marsh Lake Storage, 21 MW Wind, 2.2 MW WTE	Option A/B #3 - Marsh Lake Storage & Gladstone Div., 21 MW Wind	Option A/B #4 - Marsh Lake Storage & Gladstone Div., 21 MW Wind, 2.2 MW WTE
No DSM/SSE						
Base Case	28.0	NA	NA	NA	NA	NA
Scenario A	28.0	25.7	28.7	19.3	14.5	15.7
Scenario B	28.0	23.8	25.1	18.5	14.2	15.2
With DSM/SSE						
Base Case	28.0	NA	NA	NA	NA	NA
Scenario A	28.0	51.8	34.8	39.4	29.0	32.2
Scenario B	28.0	42.1	27.9	35.0	26.6	28.7
Full Utilization	28.0	15.2	NA	14.0	9.3	9.8

Present Value ("PV") Costs

An overall present value cost assessment is provided in Table 5-12 for each Minimum GHG Emissions Portfolio Option for Base Case loads, and in Table 5-13 for each Minimum GHG Emissions Portfolio Option for Scenario A and B loads. In each table, Default Diesel Portfolio PV costs are also shown for comparison. These assessments address total incremental generation costs during the planning period (2011-2030) under the relevant near-term grid load scenarios, showing outcomes both with DSM/SSE and no DSM/SSE.

Each portfolio option meets the forecast energy and capacity requirements for the grid over the planning period, relying on diesel generation and capacity to supply any shortfalls not supplied by the assumed new resource supply options.

- For example, diesel generation is assumed to be relied upon entirely before the new resource supply option is in-service, as well as for any shortfalls in energy or capacity after the new option is in service.
- Diesel is assumed to be relied upon to supply capacity as well as energy shortfalls. The present value assessment for new capacity solely to meet reliability requirements (i.e., diesel capacity

additions) includes all capital costs (i.e., does not address only annualized costs over the planning period). Capacity benefits are assumed as described for each resource option in Section 5.1[159].

- New resource option present value costs include all annualized costs over the planning period (i.e., residual asset values that remain after 2030 are not addressed).

The analysis shows present values with and without the assumed DSM/SSE to facilitate assessment of the extent to which uncertainty regarding the assumed DSM/SSE may affect the conclusions.

The present value costs for renewable resource portfolio options shown in Table 5-12 and 5-13 reflect (in part) the assumption under all scenarios (based on best available information) that industrial loads drop off the grid system in 2021. With planned aggressive non-industrial DSM measures over the planning period, it is expected that there would be minimal diesel displacement opportunities under each load scenario after 2021 until after 2030.

Base Case Load PV Costs

Figure 5-5 summarizes the PV cost changes for the Minimum GHG Portfolio Options selected for the Base Case load scenario. Cost changes are shown in percentage terms relative to the Default Diesel Portfolio. Under the Base Case load scenario, over the 20-year planning period each Minimum GHG Portfolio Option PV cost is 12-33% higher (i.e., more costly) than the Default Diesel Option[160].

[159] Capacity contributions: Marsh Lake Storage (1 MW); 21 MW Wind (5 MW for DRUPS); 15 MW Wood Biomass (15 MW); WTE (2.2 MW). No capacity benefits contributed by Gladstone Diversion or 10.5 MW Wind resource options.

[160] Figure 5-5 shows in contrast very low percent change in PV costs for these option when assessed at the much higher Scenario A and B loads. This simply reflects the small scale of these options relative to these higher loads (i.e., most of the energy requirements in the pre-2021 period are met with diesel generation under these Portfolio Options and the higher load scenarios).

Figure 5-5: Change in PV Costs (%) Minimum GHG Portfolio Options Compared to Default Diesel Portfolio – Base Case Load

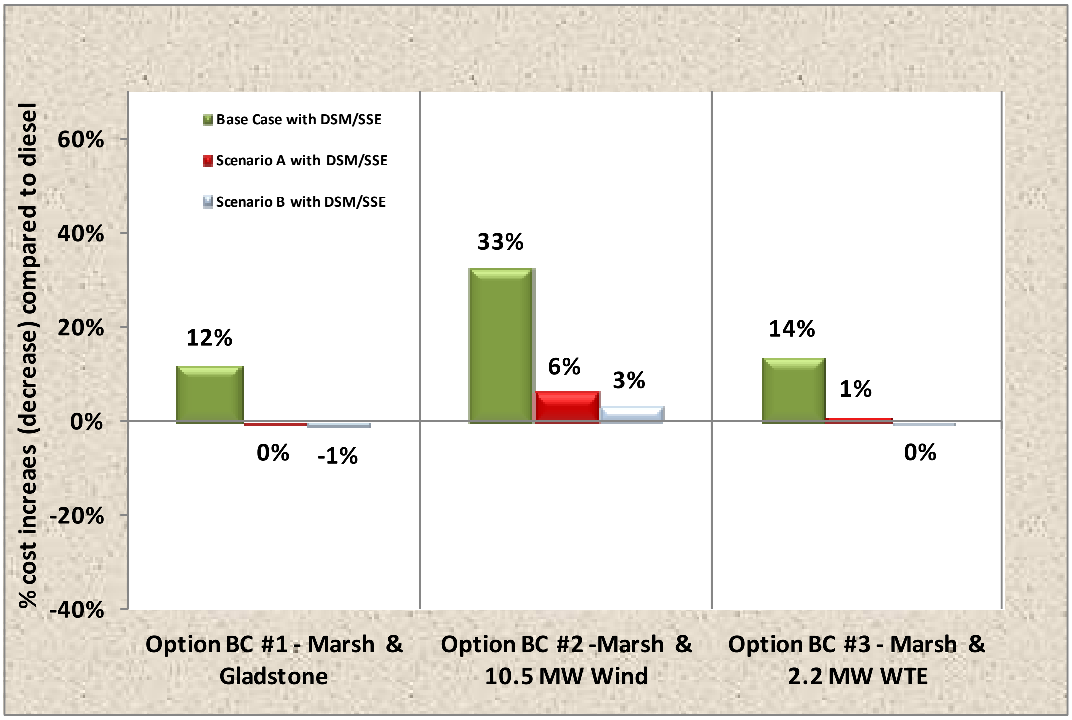


Figure 5-5 shows that the least cost Minimum GHG Portfolio Option for Base Case load is Option Base Case #1 with Marsh Lake Storage & Gladstone Diversion (12% higher PV costs than diesel) – in contrast, if Gladstone Diversion is not available, Option Base Case #3 (Marsh Lake Storage and 2.2 MW WTE) is less costly than Option Base Case#2 (Marsh Lake Storage and 10.5 MW Wind) – Option Base Case #3 PV cost increase over diesel is 33% while Option BC#2 PV cost increase over diesel is 14%.

Table 5-12 provides the comparative percent diesel displacement for each option during the key 2015-2019 period (when mine loads are still present), as well as PV costs for each option over the 20-year planning period.

Table 5-12: Present Value Costs (2010$million) - Minimum GHG Portfolio Options & Diesel Base Case Load

	Default Diesel Portfolio	Option BC #1 - Marsh Lake Storage & Gladstone Diversion	Option BC #2 - Marsh Lake Storage, & 10.5 MW Wind	Option BC #3 - Marsh Lake Storage and 2.2 MW WTE
Diesel Displaced 2015-2019[1]		62%/95-97%[2]	95%	68%
Present Value Costs (2010$million)				
No DSM/SSE				
Base Case	164.6	135.5	157.8	154.5
Scenario A	283.5	248.0	263.2	266.2
Scenario B	363.7	326.3	342.2	343.4
With DSM/SSE				
Base Case	98.1	110.0	130.0	111.9
Scenario A	204.0	203.5	216.3	206.6
Scenario B	281.2	278.4	289.9	280.5

1. Percentage GHG emissions displaced with assumed DSM/SSE.
2. Diesel displacement average is 62% for 2015-19; increases to between 95-97% in 2018-19 when Gladstone is in service.

Based on the objective for these Portfolio Options (i.e., to minimize GHG emissions), Option Base Case #2 (Marsh Lake Storage & 10.5 MW Wind) provides the greatest GHG displacement under Base Case load; however, it also requires much higher PV costs than either of the other two options. If Gladstone Diversion can be developed by 2018, after 2017 Option Base Case #1 provides much greater diesel displacement than Option Base Case #3 and also has lower PV costs.

In more detail, Table 5-12 and Figure 5-5 highlight the extent to which the Base Case load scenario would affect resource option selection. Overall, with the Base Case load it would be cost effective to develop Marsh Lake Storage plus only one of the other identified resource options. Reviewing the Base Case load scenario over the planning period with DSM/SSE, the following are indicated:

- **Option Base Case #1 (Marsh Lake and Gladstone)** – This option provides the largest potential future reduction in grid GHG emissions (up to 97% reduction after Gladstone Diversion is in-service) at the lowest overall PV cost compared to the other GHG reduction portfolio options. However, this overall reduction in GHG emissions and overall PV cost depends on the ability to secure Gladstone by 2018 (until 2018 there would be only 62% reduction in diesel requirement).
- **Option Base Case #2 costs (Marsh Lake and 10.5 MW Wind)** – This option has a higher overall PV cost compared to the other options but provides much higher grid GHG reductions that

can be feasibly secured by 2015 under these other options and with a lower level of regulatory risk than applies to Option BC #1. Development of the 10.5 MW Wind resource option would provide a first stage of a potentially much larger future wind project at the selected site.

- **Option Base Case #3 costs (Marsh Lake and 2.2 MW WTE)** – This option provides the lowest GHG reduction benefit (at only 68% during the 2015-19 period). It has a 14% lower PV cost than Option BC #2, but provides almost 30% less reduction of GHG emissions.

Without DSM/SSE, all options are less costly than the Default Diesel (Option BC #1 remains the lowest cost option and Option BC #2 remains the highest cost option).

Scenario A and B Load PV Costs

Figure 5-6 summarizes the PV cost changes for the Minimum GHG Portfolio Options selected for Scenario A and B loads with DSM/SSE. Percentage cost changes are shown relative to the Default Diesel Portfolio.

In summary, with DSM/SSE over the 20-year planning period each portfolio option PV cost under Scenario A load is 16% or more higher (i.e., more costly) than the Default Diesel Option (7% or more under Scenario B load), except for Option A/B #1 (Marsh & 15 MW Wood Biomass) with no Wood Biomass O&M (operation) after 2020 – compared to the Default Diesel Option, the PV cost for this exception is 8% more costly under Scenario A and 4% less costly under Scenario B. The exception highlights the relevance of the Wood Biomass option's flexibility (relative to the other Min GHG options) to shut down when mine loads are assumed to shut down.

Ignoring the shut down option for Wood Biomass, Figure 5-6 shows that the least cost Minimum GHG Portfolio Option for Scenario A and B load is Option A/B#3 with Marsh Lake Storage & Gladstone Diversion plus 21 MW Wind (18% higher PV costs than diesel under Scenario A). In contrast, if Gladstone Diversion is not available, Option A/B #2 (Marsh Lake Storage, 21 MW Wind and 2.2 MW MTE) is less costly than sustained operation of Option A/B #1 (Marsh Lake Storage and 15 MW Wood Biomass) – at Scenario A load, the portfolio Option A/B#2 PV cost increase over the Default Diesel portfolio is 20% while Option A/B#1 PV cost increase over diesel is 45%[161].

[161] Sensitivity tests with mine loads extended to 2025 indicate some PV cost savings relative to diesel for all options other than Option A/B #1 without provision for shut down (at Scenario B loads and/or extension of mine loads to 2030, even Option A/B#1 shows PV cost savings relative to diesel).

Figure 5-6: Change in PV Costs (%) Minimum GHG Portfolio Options Compared to Default Diesel Portfolio – Scenario A and B Loads

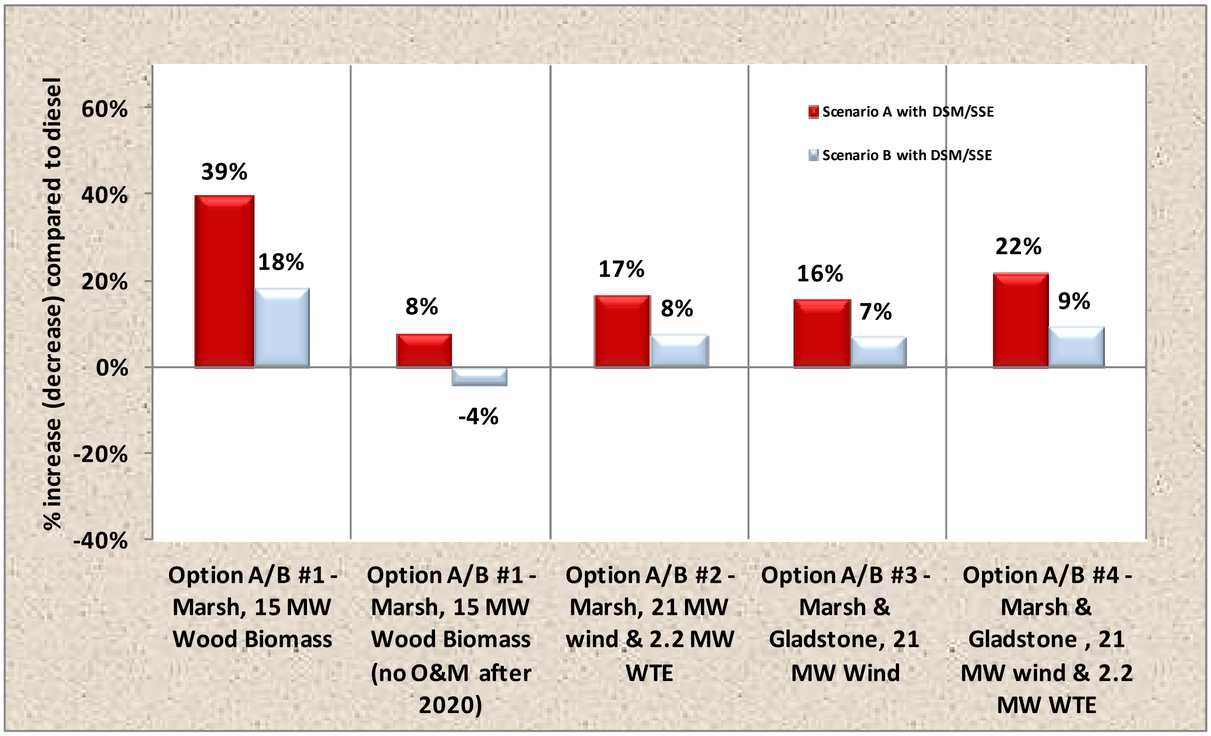


Table 5-13 provides the comparative percent diesel displacement for each option with DSM/SSE during the key 2015-2019 period (when mine loads are still present), as well as PV costs for each option over the 20-year planning period.

Based on the objective for these Portfolio Options (i.e., to minimize GHG emissions), Option A/B #1 (Marsh Lake Storage with 15 MW Wood Biomass) provides the greatest GHG displacement under Scenario A or B load; it also requires much higher PV costs than either of the other three options unless it is shut down after 2020. However, if the Wood Biomass plant is shut down after 2020 when mine loads are assumed to be shut down, Option A/B #1 with DSM/SEE has a lower PV cost than any of the other Min GHG Portfolio Options examined (under Scenario B loads, this PV cost is also slightly lower than the Default Diesel PV cost). Selection of Option A/B #1 would mean that development of the additional resource options (e.g., wind, Gladstone Diversion or 2.2 MW WTE) would not be cost effective. Option A/B #1 has less regulatory risk than options involving Gladstone Diversion (Options A/B #3 and #4).

If Option A/B #1 is not selected, the key issue affecting option selection becomes the availability of the Gladstone Diversion Project.

- If the Gladstone Diversion can be developed by 2018 along with Marsh Lake Storage by 2015, after 2017 Option A/B #4 (also includes 21 MW Wind and 2.2 MW WTE) provides diesel displacement similar to Option A/B #1 (over 90% for Scenario A and 70% for Scenario B) at PV costs 22% higher than the Default Diesel portfolio under Scenario A load and 9% under Scenario B.

- If the Gladstone Diversion cannot be developed by 2018, the only remaining option is Option A/B #2, with Marsh Lake Storage, 21 MW Wind and 2.2 MW WTE, that provides 70% diesel displacement under Scenario A during 2015-2019 at 17% higher PV cost than the Default Diesel portfolio.

Table 5-13: Present Value Costs (2010$million) - Minimum GHG Portfolio Options & Diesel Scenario A and B Loads

	Default Diesel Portfolio	Option A/B #1 - Marsh Lake Storage and 15 MW Biomass	Option A/B #1 - Marsh Lake Storage and 15 MW Biomass (No O&M after 2020)	Option A/B #2 - Marsh Lake Storage, 21 MW Wind, 2.2 MW WTE	Option A/B #3 - Marsh Lake Storage & Gladstone Div., 21 MW Wind	Option A/B #4 - Marsh Lake Storage & Gladstone Div., 21 MW Wind, 2.2 MW WTE
Diesel Displaced 2015-2019[1]						
Scenario A		90%	90%	72%	70%/84%[2]	81%/92%[2]
Scenario B		70%	70%	50%	49%/61%[2]	58%/70%[2]
Present Value Costs (2010$million)						
No DSM/SSE						
Scenario A	283.5	289.9	277.1	257.9	250.5	257.5
Scenario B	363.7	349.3	337.6	329.3	323.8	327.2
With DSM/SSE						
Scenario A	204.0	284.1	220.4	238.0	236.0	248.8
Scenario B	281.2	332.6	269.0	302.3	300.4	307.2

1. Percentage GHG emissions displaced with assumed DSM/SSE.
2. Lower diesel displacement is average for 2015-19, assuming Gladstone in-service by 2018.
The higher displacment value occurs when Gladstone in service (assumed 2018-19).

If no DSM/SSE is assumed all options have lower PV values compared to the default diesel scenario with the exception of Option A/B#1 under Scenario A loads which has a PV cost $6.4 million higher than diesel. Cost savings compared to diesel under Scenario A loads with no DSM/SSE range from $33 million (Option A/B #3 under Scenario A loads) to $6.4 million (for Option A/B#1 if Wood Biomass plant shut down after 2020). Cost savings compared to diesel under Scenario B loads with no DSM/SSE range from $40 million (Option A/B#3) to $14.4 million (Option A/B#1). The PV cost information suggests that without DSM/SSE (which implies higher diesel displacement opportunities), Option A/B #1 would be less competitive with diesel than the other Min GHG Portfolio options examined.

5.3 YUKON GREENHOUSE GAS EMISSIONS IMPACT

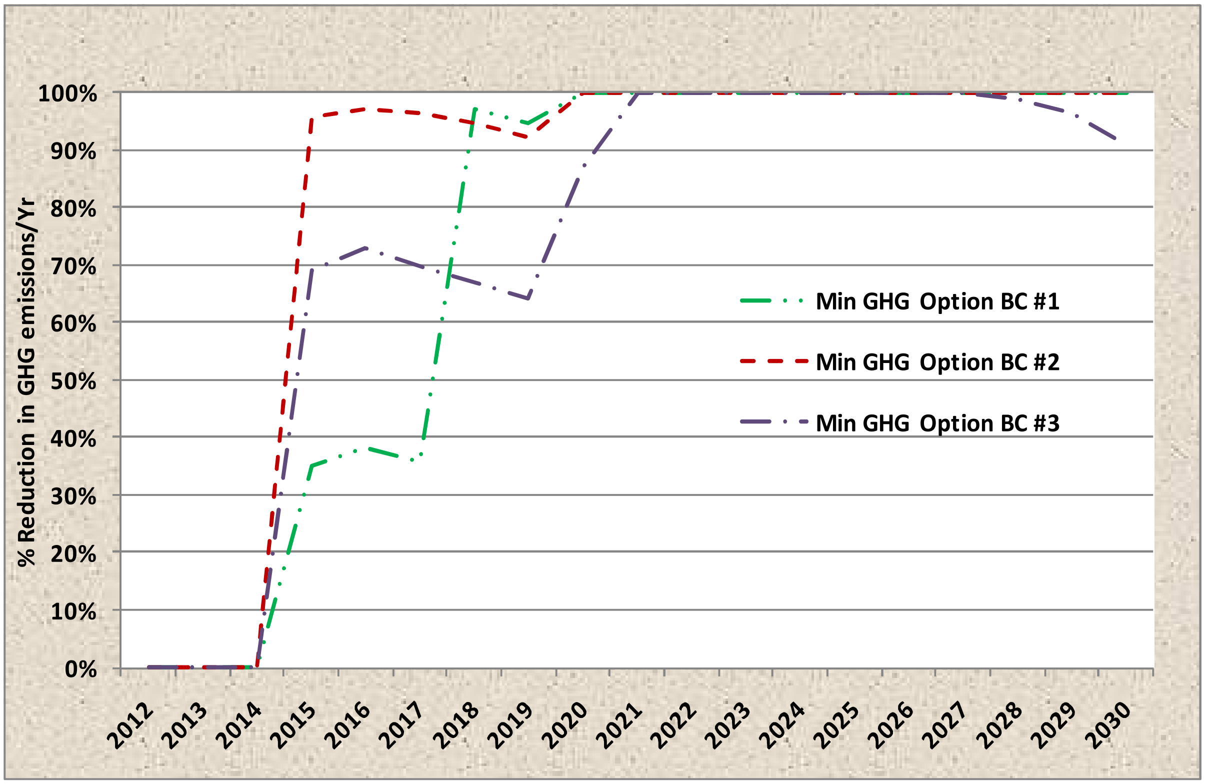
As reviewed in Section 4.3, overall Yukon Energy GHG emissions from grid power generation under the Default Diesel Portfolio vary a great deal depending on the load forecast.

- During 2012-2014 with assumed DSM/SSE starting from 2013, emissions range from 8,100 tonnes/year to 9,700 tonne/year under the Base Case, 57,800 tonnes/year under Scenario A, and 71,700 tonnes/year under Scenario B.
- During the 2015-2020 period with DSM/SSE, Base Case grid GHG emissions are small relative to Scenario A and B emissions (i.e., peak annual emissions during this period under the Base Case load (12,400 tonnes/year) are only 20% of those under Scenario A load (62,400 tonnes/year) and 12% of peak emissions under Scenario B load (101,300 tonnes/year)).
- As a result of off-grid mine developments, grid-related power generation emissions are expected to constitute a declining share of overall Yukon power generation emissions (e.g., during the 2015-2020 period), peak Scenario A (with DSM/SSE) emissions from grid power generation under the Default Diesel Portfolio could fall from approximately 26% to about 7% of off-grid mine-site power generation emissions (which are projected potentially at 232,400 tonnes/year by 2015 and 749,800 tonnes/year by 2020).

Under all non-diesel resource options there is assumed to be no ability to displace diesel and GHG emissions until 2015 (as no potential resource options are assumed to be in service prior to that date).

Figure 5-7 provides for each Minimum GHG Emissions Portfolio Option with Base Case load the percent of grid GHGs emissions displaced each year relative to the Default Diesel Portfolio. Option BC #2 (Marsh Lake Storage and 10.5 MW Wind) achieves the highest GHG emissions reduction (over 90%) on a consistent basis after 2014. Option BC #1 (Marsh Lake Storage and Gladstone Diversion) achieves high levels of GHG emission reduction after 2017 (when Gladstone Diversion is assumed to come into service). All options achieve high percent GHG emissions reduction after 2020 simply due to the very low levels of diesel generation forecast during this period (no diesel is forecast in 2021 or 2022).

Figure 5-7: Grid GHG Reductions: Minimum GHG Emissions Portfolio Options – Base Case Load 2012-2030

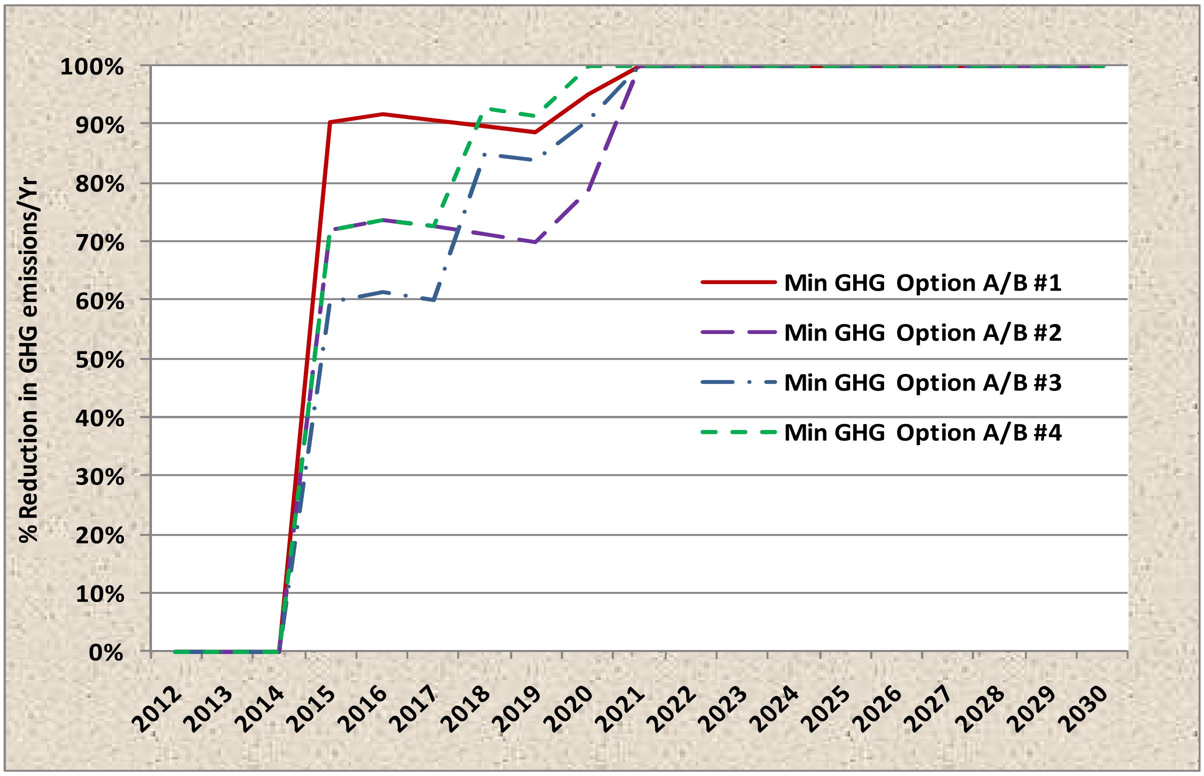


GHG's (tonnes/yr)Displaced- Base Case with DSM/SSE

	2012	2015	2020	2025	2030
Total Grid GHGs available to be displaced	**8,067**	**10,635**	**6,079**	**1,255**	**5,273**
Option BC #1 - Total GHG's Displaced	-	3,737	6,079	1,255	5,273
Option BC #2- Total GHG's Displaced	-	10,185	6,079	1,255	5,273
Option BC #3 - Total GHG's Displaced	-	7,324	5,273	1,255	4,794

Figure 5-8 provides for each Minimum GHG Emissions Portfolio Option with Scenario A load the percent of grid GHGs displaced each year relative to the Default Diesel Portfolio. Option A/B #1 (Marsh Lake Storage and 15 MW Biomass) achieves the highest GHG emissions reduction (90%) on a relatively consistent basis after 2014. Prior to 2017 this option achieves reductions 25% higher than Option A/B #2 and Option A/B #4 and 50% higher than Option A/B #3. After 2017, both Option A/B #3 and Option A/B #4 are assumed to have Gladstone Diversion in service and achieve higher overall levels of GHG emissions reductions. All options achieve high precent GHG emissions reduction after 2020 simply due to the very low levels of diesel generation forecast during this period (no diesel is forecast in 2021 or 2022).

Figure 5-8: Grid GHG Reductions: Minimum GHG Emissions Portfolio Options – Scenario A Load 2012-2030

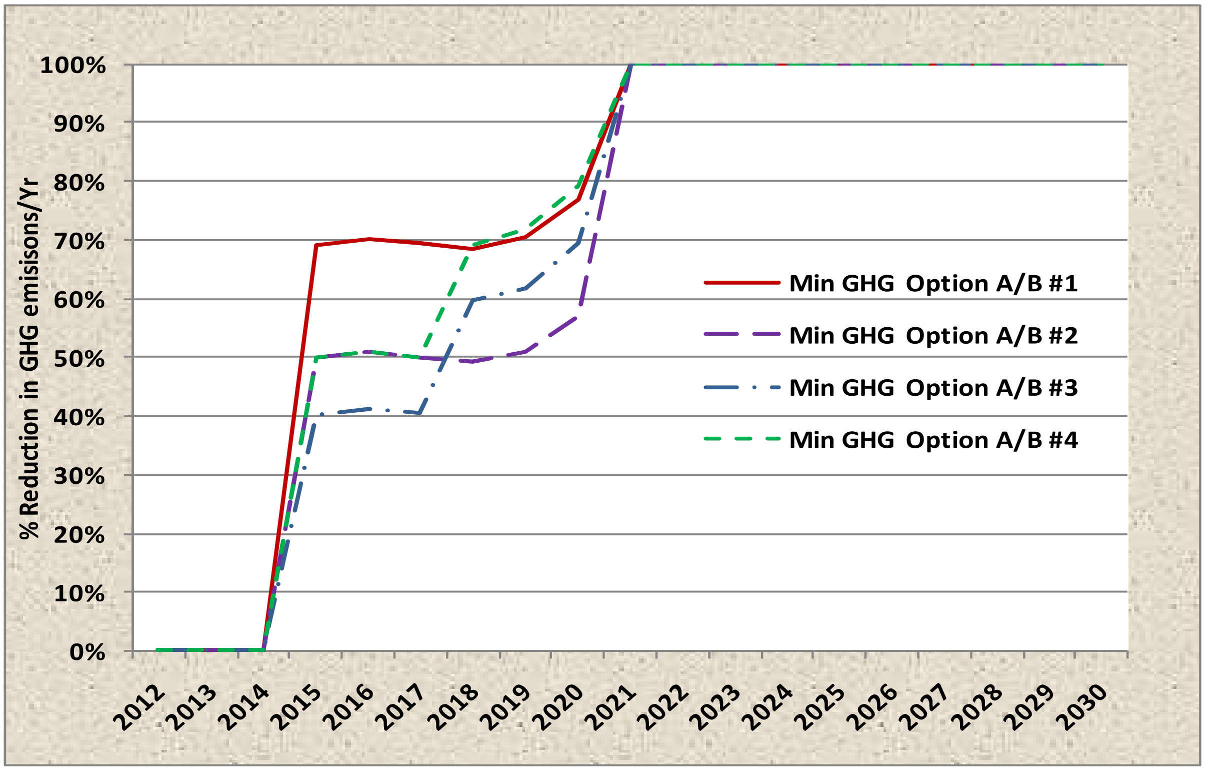


GHG's (tonnes/yr) Displaced - Scenario A with DSM/SSE

	2012	2015	2020	2025	2030
Total Grid GHG's available to be displaced	**8,067**	**59,420**	**50,776**	**1,255**	**5,273**
Option A/B #1 - Total GHG's Displaced	-	53,683	48,225	1,255	5,273
Option A/B #2 - Total GHG's Displaced	-	42,801	40,009	1,255	5,273
Option A/B #3 - Total GHG's Displaced	-	35,498	46,103	1,255	5,273
Option A/B #4 - Total GHG's Displaced	-	42,801	50,776	1,255	5,273

Figure 5-9 provides for each Minimum GHG Emissions Portfolio Option with Scenario B load the percent of grid GHG emissions displaced each year relative to the Default Diesel Portfolio. The comparison of GHG reduction benefits for each Portfolio Option is very similar with the analysis for Scenario A load, with Option A/B #1 achieving highest GHG emissions reductions over the period from 2015 to 2020 and Option A/B #3 and Option A/B #4 seeing materially increased GHG emissions reductions after Gladstone Diversion comes into service after 2017. The key difference under Scenario B loads is the overall lower percentage reductions in GHG emissions reduction compared to Scenario A loads (i.e., under Scenario A Option A/B #1 reduces up to 90% of GHG emissions starting in 2015 while under Scenario B loads Option A/B#1 only reduces 70% of GHG emissions over the same period. As with other load scenarios, all options achieve high percent GHG emissions reduction after 2020 simply due to the very low levels of diesel generation forecast during this period (no diesel is forecast in 2021 or 2022).

Figure 5-9: Grid GHG Reductions: Minimum GHG Emissions Portfolio Options – Scenario B Load 2012-2030

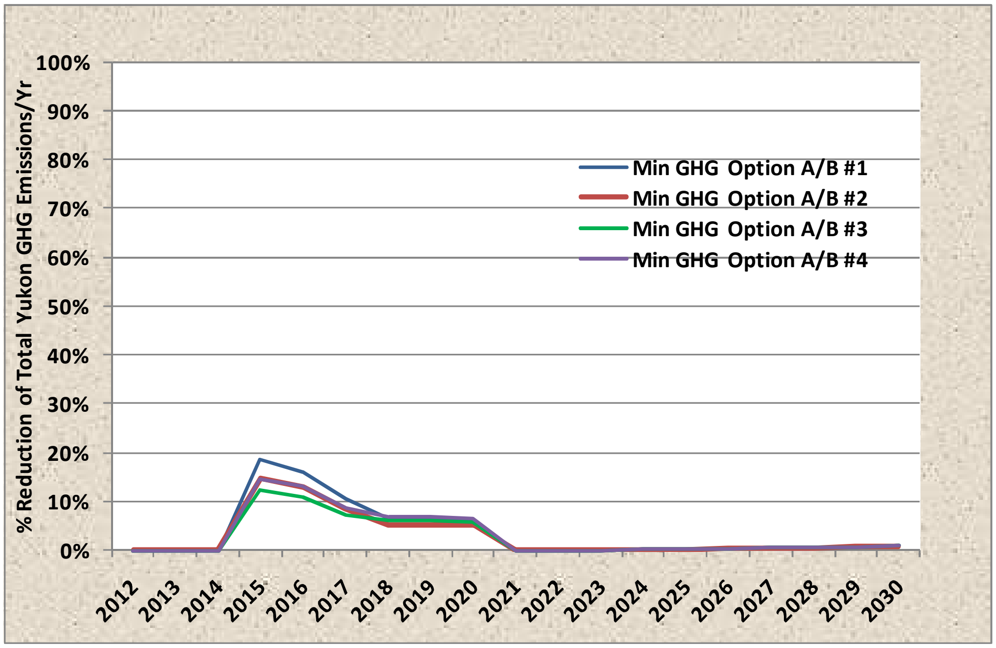


GHG's (tonnes/yr) Displaced - Scenario B with DSM/SSE

	2012	2015	2020	2025	2030
Total Grid GHGs availble to be displaced	**8,067**	**99,999**	**84,414**	**1,255**	**5,273**
Option A/B #1- Total GHG's Displaced	-	69,115	48,046	1,255	5,273
Option A/B #2- Total GHG's Displaced	-	49,852	48,046	1,255	5,273
Option A/B #3- Total GHG's Displaced	-	40,196	58,591	1,255	5,273
Option A/B #4- Total GHG's Displaced	-	49,852	66,874	1,255	5,273

As noted in Section 2 and Section 4.3, off-grid mines (at a distance that makes interconnection infeasible) are projected to develop using either on site diesel or LNG, increasing overall Yukon GHG emissions by an additional 232,400 tonnes in 2015 and 749,814 tonnes by 2020. Under each of the Minimum GHG Emissions Portfolio Options for the grid, these off-grid GHG emissions are not affected. Figure 5-10 below shows the percentage of total GHG reductions for each of the Minimum GHG Portfolio Options relative to total Yukon GHG emissions due to power generation (both grid and off-grid generation). This illustrates that on grid GHG reductions achieved through any Minimum GHG portfolio option (assuming DSM/SSE) only displace a small percentage of total Yukon GHG emissions related to power generation. After on grid mines are forecast to leave the grid in 2020 the percentage GHG reductions from Minimum GHG portfolio options declines and is minimal thereafter compared to total Yukon GHG emissions from the power generation sector (excludes GHG emissions from any new pipeline compressor stations).

Figure 5-10: GHG Reductions – Minimum GHG Portfolio Options (Scenario A with DSM/SSE) Relative to Total Yukon GHGs for Power Generation (grid and off-grid)



GHG's (tonnes/yr) Displaced - Scenario A with DSM/SSE

	2012	2015	2020	2025	2030
Total Grid GHG's available to be displaced	**8,067**	**59,420**	**50,776**	**1,255**	**5,273**
Option A/B #1 - Total GHG's Displaced	-	**53,683**	**48,225**	**1,255**	**5,273**
Option A/B #2 - Total GHG's Displaced	-	**42,801**	**40,009**	**1,255**	**5,273**
Option A/B #3 - Total GHG's Displaced	-	- **35,498**	- **46,103**	- **1,255**	- **5,273**
Option A/B #4 - Total GHG's Displaced	-	**42,801**	**50,776**	**1,255**	**5,273**
Off Grid - industrial	**25,900**	**232,400**	**749,814**	**646,214**	**609,814**
Off Grid - Utility Non-Industrial	**14,013**	**14,247**	**14,644**	**15,053**	**15,473**
Total Potential Yukon GHG Emissions (Power Generation Sector)	**47,981**	**306,067**	**815,235**	**662,522**	**630,560**

The Yukon Government Energy Strategy has identified as a priority increasing the renewable energy supply by 20% by the year 2020 to reduce fossil fuel use and related greenhouse gas emissions. While Minimum GHG Portfolio options are successful in displacing the majority of grid GHG emission over the resource planning period, grid GHG emissions are expected after the next few years to represent a declining share of overall Yukon GHG emissions from power generation. Further, aside from Wood Biomass, none of the proposed Minimum GHG Portfolio options is at a scale that fully addresses grid generation requirements over the period from 2014 to 2020, nor can any of the non-biomass Minimum GHG Portfolio options feasibly be considered for much larger potential grid loads.

The above analysis, however, addresses only near-term options that typically can be committed prior to 2015 (and includes consideration of Gladstone as a longer term option that can be committed by 2016 to address potential loads by 2018). In contrast to these near term grid-focused options, development of larger greenfield hydro sites for an expanded grid may provide for a source of clean energy supply that could more effectively reduce GHG emissions from power generation in Yukon over the longer-term.

5.4 LONG-TERM DEVELOPMENT CONSIDERATIONS

Section 5.1.2 and Table 5-1 identified long-term renewable hydro resource options for the Minimum GHG Emissions Portfolio that are potentially available to start construction before 2021 and that could provide low costs as well as low GHG emissions[162].

In summary, 17 medium to large greenfield hydro options offer both low GHG emissions and low costs per kW.h, i.e., each option has costs below 15 cents/kW.h Full Utilization LCOE, including provision for transmission connection to the current grid – nine of the options have costs below 10 cents/kW.h. Additional small hydro sites have costs below 25 cents/kW.h. These potential hydro projects constitute defined long-term legacy resource opportunities. Once developed, such opportunities could provide sustaining benefits for many decades, in the same way that past hydro developments at Whitehorse, Aishihik and Mayo benefit Yukoners today (as well as provided benefits in earlier decades when initially developed).

The challenge is to assess what basis, if any, exists today to consider long-term planning during the next five years (and if so, what specific planning) regarding such potential hydro resource developments.

- Given a list of screened hydro resource options, the key initial issue is to confirm potential ability within the next 10 years to connect loads that could fully utilize the specific resource options over a reasonable sustained number of years.

- As discussed in Section 3.2.2 and Table 3-1, medium to large scale greenfield hydro generation options with full utilization LCOEs of 5 to 11 cents/kW.h can be characterized with high affordability (i.e., low cost)[163]; however, generation from these medium to large scale greenfield hydro projects would clearly not come close to being fully utilized under current forecast grid loads; and, until reasonable levels of utilization are forecast over 20-30 or more years, such capital intensive resource options would in reality remain highly unaffordable in Yukon.

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[162] Geothermal and clean coal resource options were noted as potential future options to provide both low costs and low GHG emissions but, for the reasons noted, for planning purposes today were not considered to be available to start construction before 2021.

[163] Such cost estimates remain subject to considerable risk and uncertainty until more detailed site and feasibility study work provides updated assessments for specific short-listed options, including updated review of all relevant potential regulatory and approval considerations.

In order to meet these challenges, specific hydro developments that could come into service by 2021 will need to be identified that would justify expansion of the grid to connect one or more new longer-term (i.e., 20-30 year) off-grid mine developments. As noted, such expansion and extension of grid mine loads would help to reduce Forecast LCOE and adverse annual cost impact for all feasible renewable resource options.

The following example outlines the potential cost impacts of a new hydro project that is fully utilized with LCOE cost of 10 cents/ kW.h (2010$) that comes into service in 2019:

- Assuming 2% inflation, the initial year cost in 2019 would approximate 19.7 cents/kW.h[164]; this cost would then decline in subsequent years (so that, in 2010, the levelized lifetime cost over 65 years would be 10 cents per kW.h).
- Marsh and Gladstone hydro costs projected to 2019 would be lower (around 14 cents per kW.h with inflation and assuming the in-service dates in the earlier analysis as well as Scenario A loads with DSM/SSE and mine loads still connected).
  - Under the same assumptions, other near-term renewable resource options examined earlier would have average costs in 2019 as follows:
    - Wind and WTE – costs at 26-27 cents/ kW.h; these costs tend to decline as capital cost depreciates.
    - Wood biomass (15 MW at $104/tonne feedstock cost) - costs at 33 cents/kW.h; these costs are affected by ongoing cost inflation for the feedstock and staffing components.
  - Diesel fuel and O&M costs (for a new unit) in 2019 are assumed in earlier projections at 31.1 cents/kW.h. In contrast, as reviewed in the following section (Section 6), LNG-based power supply could be approaching 17 cents/kW.h by 2019 and would likely be subject to ongoing escalation at rates faster than inflation.
- The key to overall impacts on rates and GHG emissions is the extent to which the new hydro resource, in addition to being of relatively low cost compared to available supply options, is also sufficiently large in scale to have a material impact in displacing non-renewable power generation.

[164] Initial year costs per kW.h for a fully utilized hydro project will be approximately 65% higher than the levelized cost, assuming a 65 year economic life (all costs in the same constant dollars, i.e., no inflation impacts considered). By way of example, a hydro project with a levelized cost (2010$) of 10.0 cents/kW.h over 65 years would have a year one operation cost of 16.5 cents/ kW.h (2010$). This cost would decline in future years (even in "real" term, net of inflation) as the rate base is depreciated.

Potential off-grid load opportunities during the period to 2021 and related potential hydro development prospects are reviewed below, followed by an overview of related planning required during the next five years to protect the opportunity to start construction on any of these hydro projects prior to 2021.

Potential Off-Grid Load & Hydro Resource Opportunities

Figure 2-4 indicated potential off-grid mine developments before 2021 that could provide challenging opportunities for major new legacy generation projects to displace up to 1,000 to 1,500 GW.h/year of ongoing fossil fuel equivalent generation. This potential scale of new power use, with opportunities for 20 to 30 or more year life, provides justification for assessing appropriate near-term planning activities to protect Yukon ability to start construction prior to 2021 of new renewable greenfield hydro projects.

A first step in such planning is to identify specific off-grid diesel displacement opportunities that would need to be pursued in order to secure the type of sufficiently large and sustained load to justify development of new lower cost legacy assets. The following is an overview of relevant load opportunities (see Figures 1-2 and 3-1 for maps showing the location of these projects):

- Fossil fuel generation for off-grid mines by 2021 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 to the east of the WAF grid close to the border with NWT (147 GW.h/year), and the Northern Dancer project located near the Alaska Highway east of Teslin (250 GW.h/year)).
- If the Alaska Highway Pipeline project proceeds, the six gas compressors for this project could potentially add up to 1,470 GW.h/year of additional equivalent energy requirement opportunities[165] by approximately 2020/21 that would also be sustained over 25 years in the event that GHG emission concerns support electrification initiatives.
- In each instance, development of the above loads will apparently be contingent on factors external to Yukon Energy's ability to supply grid generation. In addition, none of these developments appear to be contingent on access to grid power in Yukon (i.e., each mine project currently plans to rely on either diesel or LNG fuel for onsite power generation and the Alaska

[165] This estimate includes only an initial four compressor stations (assumes approximately 245 GWh/year per compressor station for an approximate 33 MW equivalent peak load per station. Six compressor stations are planned in Yukon. An additional heater station with a similar load is also planned.

Highway Pipeline project compressor stations is currently planned to rely on natural gas[166]). To the extent that these "off-grid" energy loads materialize in Yukon before 2021, overall energy sector GHG increases would dwarf any gains otherwise from on grid DSM or other measures.

Table 5-14 provides a summary of major potential off-grid industrial load opportunities over the resource planning period and the potential greenfield hydro development opportunities that such loads may support to provide new low cost legacy assets over the long-term.

[166] Based on YEC discussion with the proponent, grid power will be sought where feasible only for compressor station service (1.5 MW for first station, and 300 kW for four other stations, and 350 kW for the sixth station) and the gas heater station (150 MW). Potential co-generation of up to 5 MW might occur at each compressor station for sale to YEC. Discussion is possible on YEC providing grid power to compressor stations - and this could be done on a station-by-station basis.

Table 5-14: Yukon Industrial Load Opportunities and Potential Hydro Sites

POTENTIAL INDUSTRIAL LOAD OPPORTUNITIES

Developing low cost/low emission hydro options depends on connecting new grid loads that could adequately utilize the resource for 20-30 years

DEVELOP SOUTHERN LAKES GRID CONNECTIONS

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

DEVELOP GRID TO EAST OF ROSS RIVER

SELWYN (147 GWh/yr) **& (MACTUNG)**
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

DEVELOP SOUTHERN GRID TO EAST NEAR ALASKA HWY

NORTHERN DANCER (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

PIPELINE COMPRESSOR - 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)

PIPELINE COMPRESSOR - 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 develpment of NORTHERN DANCER

DEVELOP CENTRAL & WESTERN YUKON GRID

CASINO MINE (940.8 GWh/yr)
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

POTENTIAL HYDRO DEVELOPMENT OPPORTUNITIES

		Installed Capacity (MW)	Annual Energy (GWh)	Levelized Cost (c/kWh)
Small Hydro Projects (<10MW)				
	Southern Lakes Projects			
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
Medium Hydro Projects (<60 MW)				
< 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
Medium Hydro Projects (<60 MW)				
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
Large Hydro Project (> 60 MW)				
10-15 c/kWh	Liard Canyon	93.5	659	12.2
Large Hydro Project (> 60 MW)				
< 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

*Transmission costs to connect to existng grid are 54-55% of levelized cost.

Each of the major potential load opportunities is outlined below:

- **Casino Mine Opportunity (940 GW.h/yr for 20-30 years):** A large hydro project in the 69 to 100 MW range (450 to 700 GW.h/year) reasonably near the CSTP grid could match a large share of the Casino load, i.e., Fraser Falls Low (700 GW.h/year), Granite Canyon Low (600 GW.h/year) and Slate Rapids/Hoole (459 GW.h/year) would be potential candidates. Other large hydro options are either too large (Fraser Falls High at over 2,000 GW.h/year or Granite Canyon High at over 1,780 GW.h/year), or too far away (Detour Canyon or Liard Canyon). Development of such hydro opportunities would require further development of the central and western grid. To be competitive, hydro options would need to be less costly than LNG/natural gas generation.

- **Northern Dancer Mine Opportunity (200-300 GW.h/yr for 30 years):** This load creates opportunities for eastern Yukon medium-scale hydro sites in the Watson Lake area (e.g., False Canyon at 370 GW.h/year) and could provide the basis for developing the southern grid east along the Alaska Highway. In the event that the Alaska Highway Pipeline is also developed, development of larger hydro sites in this area (e.g., Liard Canyon at 659 GW.h/year) could be considered. Levelized cost estimates for hydro sites in this area (e.g., Middle Canyon, Liard Canyon, False Canyon and Upper Canyon) currently reflect extensive transmission costs to connect to the current grid; emergence of major local loads such as those noted here would reduce the estimated cost of delivered power from these hydro sites. To be competitive in serving these load opportunities, hydro options would need to be less costly than LNG/natural gas generation.

- **Selwyn Mine Opportunity (147 GW.h/yr for 30+ years):** Based on location and expected mine load scale, a medium hydro project in the 17 to 30 MW range (129 to 181 GW.h/year) to the east of the northern WAF grid could match all or most of the Selwyn load and contribute to supply of the MacTung load (i.e., Finlayson River (129 GW.h/year), Slate Rapids (small) (266 GW.h/year), or Ross Canyon (181 GW.h/year) would be potential candidates). There are a number of other slightly larger potential medium hydro options in the 266 to 280 GW.h/year range that might merit consideration for the overall grid (particularly if Casino is connected), including Hoole Canyon with Storage (275 GW.h/year) or Slate Rapids (266 GW.h/year). Other medium hydro options in this target location might also merit consideration under some load combinations, even though they are much larger (Combined Slate Rapids [with powerhouse at foot of dam] and Hoole at 361 GW.h/year would likely be preferred today over False Canyon at 370 GW.h/year, given location proximity to the grid plus current level of information[167]).

- **Pipeline Compressor Loads:** Based on the location for such stations along the Alaska Highway plus expected load, a range of hydro projects sizes located as close as possible to the southern WAF grid could be considered.
    - For example, supply to only one compressor station near Whitehorse[168] would suggest medium sized hydro projects in the 266-280 GW.h/year range (Hoole Canyon with Storage or Slate Rapids); consideration of two compressor loads would indicate the need for a larger project such as Combined Slate Rapids/Hoole scheme (459 GW.h/year) or Granite Canyon Small (400 GW.h/year). If two or more compressor options are looked at in combination with Casino loads, consideration might be given to bigger scale options.
    - Pipeline development along the Alaska Highway would also create opportunities to develop hydro sites and related transmission in the east end of the Yukon route (e.g., False Canyon, Middle Canyon, Upper Canyon or Liard Canyon to supply power to one or two compressor stations)[169].

In summary, an unprecedented range of potential hydro development opportunities exist during the next five to ten years in association with major new mine and other loads currently under active consideration in southern Yukon.

In order to provide legacy benefits for Yukoners, new hydro site opportunities will likely need to be assessed in light of overall grid development considerations and the ability to ensure that a reasonable portion of new hydro supply is available to serve growing non-industrial power needs on the Yukon grid.

Even under favourable circumstances, it would likely not be feasible to pursue all of these opportunities during the 2011 Resource Plan planning period, i.e., some of the new industrial loads (if they emerge) will likely need to rely on a continuing basis upon fossil fuels (e.g., LNG or natural gas, if not diesel fuel) for onsite power generation. There are also likely to be practical constraints (e.g., planning costs and timing, overall financial risks and costs) regarding how many such hydro projects could be developed concurrently during the planning period.

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[167] Due to its distance from the grid, False Canyon's levelized cost to connect to the grid is estimated at 14.5 cents/kW.h.
[168] For example, preliminary locations indicated for a station northeast of Mendenhall Landing and a station near Jake's Corner.
[169] For example, preliminary locations indicated for a station about 68 km west of Watson Lake on the highway (south of Allegretto Lake); another station is indicated to be located southeast of Helen Lake (about 140 km west of Allegretto Lake along the highway, and east of Teslin).

Connection to the grid of any of the new off-grid mine loads identified in Table 5-14 is unlikely to occur until after the mine is developed and operating with reliance on fossil fuel power generation (i.e., new hydro site development will likely require the security of established long-term mine loads), and, to be feasible, new hydro power will need to clearly provide sustained costs savings for such mine customers to justify connection to the grid. In contrast, connection to the grid of any new pipeline compressor loads noted above may need to be planned to occur on or before the pipeline comes into service.

Required Planning Activities

If Yukon Energy is to protect opportunities to start construction before 2021 on any of the above hydro projects, considerable planning will be required through the next five years (2011-2015). Figure 5-11 provides an overview of the potential timing and key planning stages required to develop greenfield hydro project options during this period, highlighting actions needed during 2011-2015 to protect the ability to bring any such hydro option into service within the next decade and identifying currently identified potential off-grid load and development opportunities that are likely to affect hydro option planning.

The above off-grid load opportunities are each clearly subject to project-specific negotiation and joint planning with each developer to determine if mutually acceptable arrangements and opportunities can be concluded, including appropriate risk management and mitigation measures to protect all other grid-served customers from unacceptable rate-related risks.

Focusing on the above short listed hydro sites, the following overview of staging of activities provides an initial indication of near-term planning potentially needed to protect the opportunity for such developments to proceed before 2021 in response to the identified longer-term load opportunities:

- **Step 1 - Prefeasibility activities (1-2 years):** A range of activities is required to be completed by fall 2012, including further summer field investigations, to confirm technical and other feasibility, ranking and staging for potential development by 2021. These activities include (for selected sites as noted above and all related transmission requirements - it is assumed that these activities are coordinated for all sites as one set of prefeasibility planning work focused on selecting and developing one or more legacy hydro projects within the planning period):

    a) An initial pre-planning stage review during winter 2011/12 in time to allow 2012 field season activities, to confirm planning and priorities. The following suggested activities would be reviewed and modified as required during this pre-planning review.

    b) Complete coordinated engineering pre-feasibility work as required for this package of sites to provide adequate baseline information on water flows and site concept options (including transmission access and/or upgrades to existing transmission) to enable confirmation of technical feasibility and planning schedules for specific preferred concepts, including potential staging where relevant (and assessment of cumulative impacts as regards storage and water regime controls for multiple potential projects on the same river system).

c) Complete any baseline environmental studies deemed critical to project feasibility assessment.

d) Initiate consultations and joint reviews with First Nations having traditional territories impacted by any of these short listed projects (as regards possible partnership arrangements), and also initiate discussions and joint planning with potential off-grid mine customers (as regards potential PPA or other arrangements) and with government (as regards possible funding support), to confirm potential understandings as required to justify proceeding to the next stage of feasibility and environmental assessment work for specific sites.

e) Plan the above activities to allow an interim review in winter of 2011/12 to confirm the short listed sites and ongoing work plans for the next summer; in the event that information surfaces to suggest that any of the short-listed sites are not likely to be feasible for development by 2021, identify other hydro site options to be examined instead.

f) At the end of Step 1, a work plan (including budget arrangements) will be provided for Step 2 activities for remaining short listed sites that are justified for proceeding to the next planning stage. This work plan will set out risk management and staging for each remaining short listed site, including funding requirements. Based on Mayo B experience, cost requirements for Step 2 activities for any specific site could approximate 2% of final project capital costs (e.g., $10 million order-of-magnitude for a medium hydro site and $20 million order-of-magnitude for a large hydro site). Specific cost estimates relevant to the short listed hydro sites would be developed as part of the Stage 1 work.

- **Step 2 - Feasibility and Environmental/Socio-Economic Assessment and other related activities (2 years for a site):** After completion of Step 1, at least two years is likely to be needed (with another two field seasons) to complete feasibility engineering, environmental and socio-economic assessment studies, consultations and agreements as needed for each site selected (including related transmission requirements) to proceed with the required regulatory filings. This work may potentially involve multiple sites, each with different timelines for investigations, agreements and YESAA-related filings.

The following would be carried out for each selected site (includes related transmission requirements):

a) In addition to engineering and regulatory work for each selected site, related arrangements required for power purchase agreements, First Nation or other partnerships, and overall project financing/funding would also proceed as required to enable the project to proceed to Stage 3 below.

b) The approach to be undertaken for design, procurement, construction and owner administration would be finalized along with any specific risk management measures required for the project to proceed.

c) At the end of Step 2 for any specific hydro site, a project proposal would be filed with YESAB and any funding submissions and/or agreements (PPAs, partnerships, etc) that may be required for that hydro site development would also be finalized. A workplan (including budget arrangements) would be provided (and summarized in the YESAB filing) for Step 3 and subsequent activities for that hydro site's development.

- **Step 3 – YESAB Screening and Related Permitting & other pre-construction activities (2-3 years):** Given the scale of these developments, 2 to 3 years may be required to conclude Step 3 regulatory review and permitting activities plus other pre-construction activities:

  a) Regulatory reviews will include YESAB, YWB, a Part 3 review by YUB, and DFO.

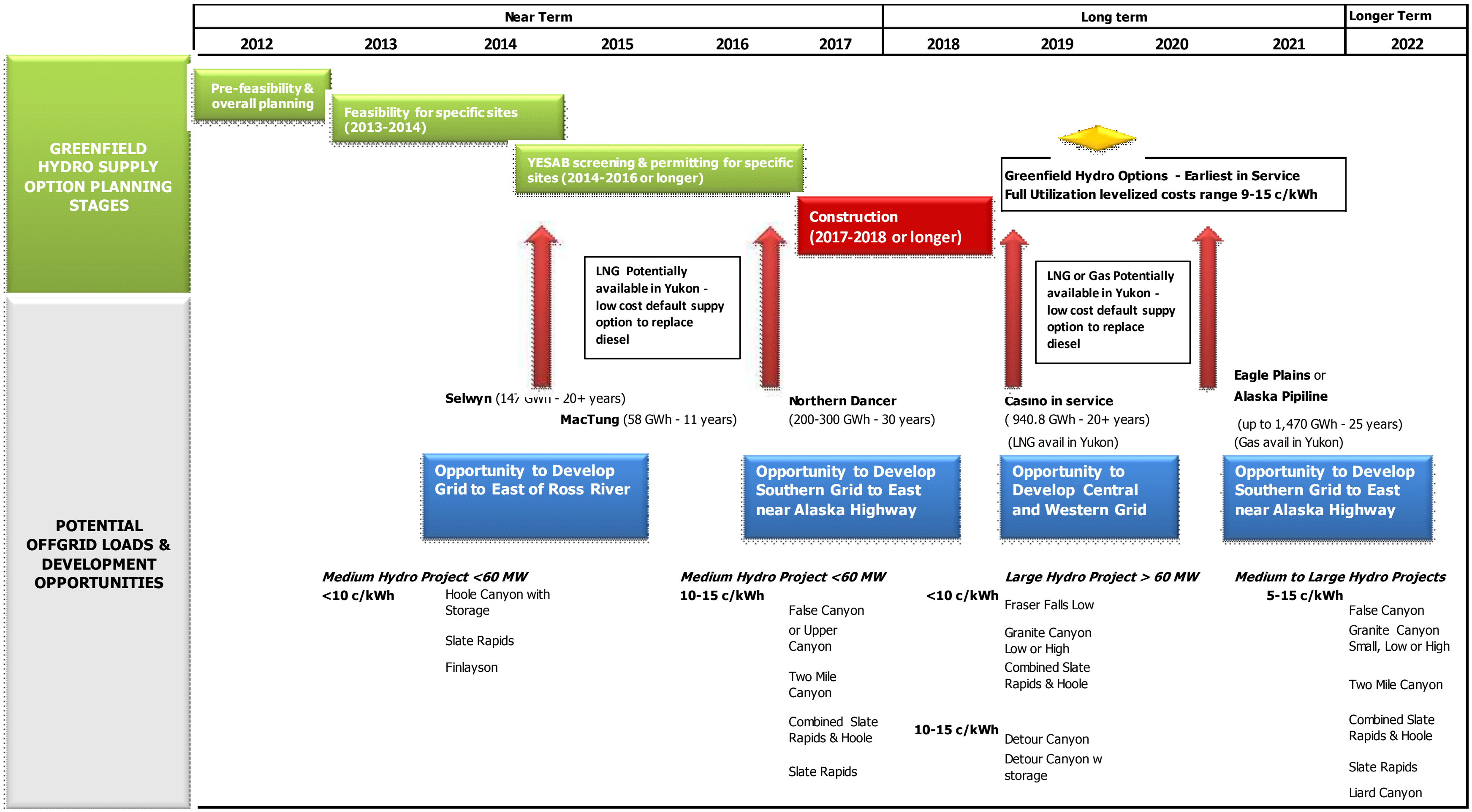
  b) Other pre-construction activities will include final design and tendering, any special procurement arrangements required for long lead equipment, all related contracting for owner administration, and financing and any agreement arrangements required for the project to proceed.

  Step 3 would conclude with a decision by YEC's Board of Directors to proceed with construction.

- **Step 4 – Project Construction (minimum 2 years):** Based on the above, the earliest that a new greenfield hydro project might come into service would be later 2018. This timing could be affected by a wide range of factors.

The Minimum GHG emissions portfolio options available in the near-term are capital intensive and inflexible, resulting in higher present value costs than diesel generation during the planning period unless major new additional loads are connected to the grid. Without a clear longer-term planning approach as discussed above, the near-term options could (as with the Default Diesel Portfolio) provide pressure to constrain costs in order to constrain rate increase impacts on ratepayers throughout Yukon, with resulting pressures to constrain connection of new loads to the grid as well as key ongoing capital spending on the longer-term resource planning options identified above. Without connection of new loads to some form of grid development, opportunities to develop new legacy renewable generation resources are likely to remain very limited.

Figure 5-11: Overview of Planning Activities for Greenfield Hydro Supply Option Development - 2011-2021



5.5 CONCLUSIONS

Renewable Minimum GHG emissions portfolio options for the near term (i.e., committed by 2015) focus on displacing grid GHG emissions over the planning period, and do not address the expected major increase in GHG emissions from new off-grid industrial power generation prior to 2020. Beyond the near-term grid-focused options, development of larger greenfield hydro sites for an expanded grid could potentially provide for a source of clean energy supply that would more effectively reduce GHG emissions from power generation in Yukon over the longer-term.

In the near-term, the relative attractiveness of Minimum GHG emissions portfolio resource options is affected by the range of potential load forecasts (after consideration of potential DSM/SSE) and uncertainties related to the ability to secure the resource option within the near-term, i.e., ability to commit by 2015 and be in-service by 2017 at the latest. Summary conclusions from Section 5 regarding near-term Minimum GHG emissions portfolio resource options include:

- Although hydro options are the least cost renewable resource options identified, new hydro resource options are very limited in the near-term due to the time needed to plan, licence and develop new greenfield sites. These options also face uncertainty and risk regarding regulatory permitting time requirements and outcomes:
    - Marsh Lake Storage could potentially be in-service by 2015; due to its small scale and low costs, it has been assumed in each resource portfolio.
    - Gladstone Diversion could potentially be in-service by late 2017; however, this project is subject to considerable regulatory uncertainty as to securing local First Nation support and necessary regulatory approvals.
    - If and when approved, Gladstone Diversion is large enough in scale in combination with Marsh Lake Storage to displace up to 97% of pre-2020 Base Case load grid GHG annual emissions from diesel - however, its economic impacts relative to diesel are sensitive to grid load risks (i.e., in combination with Marsh Lake, Gladstone Diversion has a lower PV cost than Default Diesel over the planning period only if grid loads exceed Scenario A levels with DSM/SSE).
- Under Scenario A or B grid loads, all portfolio options have higher PV costs over the planning period than diesel under the Scenario A loads with DSM/SSE, and prior to 2021 provide only limited potential to reduce annual cost impacts relative to diesel (after 2020 and assumed mine closure, these options have materially higher annual cost impacts than diesel).

- **Option A/B #1 (Marsh Lake Storage with 15 MW Wood Biomass - No O&M after 2020**) – The Wood Biomass plant allows this portfolio to provide high GHG emissions displacement on the grid (e.g., 90% displacement under Scenario A with DSM/SSE prior to 2021) while also providing the flexibility to shut the plant down (i.e., cut off O&M costs) when grid loads are assumed to drop after 2020 due to assumed mine closures. If and when loads drop significantly, there is no benefit in assuming continued operation of the wood biomass plant.
    - This portfolio has a lower PV cost over the planning period than any other Minimum GHG emissions portfolio option under Scenario A and B load cases with DSM/SSE; however, it has higher PV costs than the other options under Scenario A and B loads with no DSM/SSE, with extension of mine loads under Scenario A with DSM/SSE to 2025 or 2030 and with extension of mine loads under Scenario B with DSM/SSE to 2030.
    - The PV comparative cost advantages for the Wood Biomass plant derive from its flexibility to shut down when appropriate and thereby save O&M costs; when operating during the period prior to 2020, this portfolio option typically has annual cost impacts that are equal to or higher than the other Minimum GHG portfolio options.
- **Option A/B#3 (Marsh Lake Storage with Gladstone Diversion and 21 MW Wind)** – This portfolio provides high GHG emissions displacement on the grid (e.g., 84% displacement with Gladstone Diversion under Scenario A with DSM/SSE prior to 2020); this option also has a lower PV cost during the planning period than Option A/B #4 (same portfolio with 2.2 MW WTE added) under all Scenario A and B load cases examined with and without DSM/SSE. [Accordingly, Option A/B #4 is not considered further in Sections 6 or 7].
    - Prior to mine closures (regardless as to sensitivity tests for mine load extensions to 2025 or 2030) and under Scenario A loads with or without DSM/SSE, this portfolio option has lower annual cost impacts than any of the other Minimum GHG Emissions Portfolio options (under Scenario B loads, Option A/B #4 has slightly lower annual cost impacts prior to mine closures, but higher annual cost impacts after mine closures).
- If Gladstone Diversion is not available, **Option A/B #2 (Marsh Lake Storage with 21 MW Wind and 2.2 MW WTE)** – Excluding wood biomass or Gladstone Diversion, this portfolio provides the maximum feasible near-term GHG emissions displacement on the grid (e.g., 72% displacement prior to 2021 under Scenario A with DSM/SSE);

compared to Option A/B #3, it has a slightly higher PV cost over the planning period, slightly higher annual cost impacts prior to the assumed mine closures, and slightly lower annual cost impacts after the assumed mine closure.

Looking at the longer term (i.e., start project construction before 2021), new hydro resource developments currently offer the best opportunities to reduce costs as well as GHG emissions – subject to adequate long-term loads being connected to the grid to sustain such new hydro developments.

During the next five to ten years an unprecedented range of potential hydro development opportunities exist in association with major new mine and other loads currently under active consideration off the grid in southern Yukon. In particular, several major new long-term load opportunities (e.g., 20 to 30 or more years) located in different areas are relevant during this planning period (e.g., the Selwyn, Northern Dancer and Casino mine projects and the Alaska Highway Pipeline project). Opportunities to start construction before 2021 on any of these hydro developments will require major hydro-resource planning activities through the next five years (2011-2015) as well as confirmation that one or more of these new loads is in fact being developed. Connection to the grid of any of these major new loads is also likely to be dependent on new hydro generation being less costly than LNG or natural gas fuelled generation that is expected to be available to these off-grid loads (see Section 6).

6.0 LNG TRANSITION PORTFOLIO OPTIONS

6.1 DEFINING THE PORTFOLIO OPTIONS

LNG Transition Portfolio options aim to use LNG or natural gas to displace diesel fuel as the on grid and off-grid default electricity supply source throughout most Yukon areas while facilitating concurrent development of longer-term legacy grid renewable resource options as soon as is appropriate.

LNG options in the 2011 Resource Plan are focused primarily on displacing near-term diesel grid loads under Scenarios A or B along with off-grid diesel generation at Watson Lake and industrial mine sites. Potential LNG opportunities to displace grid diesel under Base Case loads are also examined. In each instance, the LNG option is directed at immediate and material near-term reductions in costs and GHG emissions in Yukon relative to the Default Diesel Portfolio. Overall, LNG and/or natural gas is examined as a new fuel option that retains flexibility for power generation as well as diversity for energy use opportunities (e.g., for electricity generation locations and for end use sectors such as transportation) similar to that provided today by diesel fuel.

LNG Transition portfolio options also encourage planning for, and pursuit of, cost effective and environmentally responsible hydro, wind or other renewable legacy resource development over the longer-term planning horizon to secure sustained and larger reductions in costs and GHG emissions as soon as economically feasible in the future.

6.1.1 Background on Current LNG Supply Opportunities for Yukon

The key features potentially offered by liquefied natural gas (LNG) as a near-term option include flexibility similar to diesel generation, but with reduced costs and reduced GHG emissions.

Near-term supply of LNG in Yukon is facilitated by abundant natural gas supplies in BC and Alberta being used to develop LNG liquefier facilities that can supply cost competitive LNG by truck to Yukon. Longer-term development of natural gas supplies in Yukon (e.g., through the Alaska Highway Pipeline Project, Eagle Plains gas development, or any other source[170]) would allow direct access to natural gas in some Yukon locations plus development of local Yukon LNG liquefier facilities to supply LNG to other locations.

New opportunities to consider LNG as a major fuel option to displace oil products in Yukon reflect recent natural gas supply softness that has driven gas prices to historically low levels relative to oil prices, and new shale gas supplies that are expected to contribute to ongoing low prices[171]. Uncertainty is noted about environmental issues regarding shale gas development as well as the timing of development of new shale gas reserves[172].

LNG opportunities today in Yukon are confirmed and facilitated by major new LNG facility development currently planned in BC and Alberta (including facilities for LNG sale into higher priced Asian export markets). The business case for such new LNG export confirms the expectation that it is profitable on a sustained basis (i.e., for the economic life of the new LNG facilities) to buy inexpensive gas in BC/Alberta indexed to lower 48 pipeline gas cost (Henry Hub and NYMEX), and cover the capital and operating costs for liquefying the gas to LNG and transporting the LNG to market by ship for sale at world export market prices. The expected sales margin (i.e., the difference in prices for gas between the North American and Asian markets) for such LNG exports confirms an expectation that natural gas prices in North America will remain significantly depressed relative to oil prices.

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[170] Proponents of the Alaska Pipeline Project provided a project schedule in September 2011 meetings in Alaska indicating first gas in 2020 and full gas in 2021, assuming an October 2012 FERC filing and project sanction before mid-2015. Based on YEC discussion with the proponent, if the pipeline does its own compression the Yukon power requirement will be for station service (1.5 MW for first station near Beaver Creek, and 300-350 kW for the other five stations). Potential co-generation of up to 5 MW might occur at each compressor station for sale to YEC. Discussion is possible on YEC providing grid power to compressor stations - and this could be done on a station-by-station basis.There is currently no timing or plan for development of Eagle Plains, but potential options may emerge tied to development of a major new load such as the Casino mine.

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

[172] Production from shale gas may involve hydraulic fracturing – this practice has come under international scrutiny due to environmental and health safety concerns and has been suspended or banned in some countries. Such concerns relate to uncertainty regarding the extent to which this process pollutes fresh water zones, contaminates surface or near-surface water supplies, impacts rock shelf causing seismic events or leads to surface subsidence.

The following are noted in regard to the development of specific LNG facilities in BC and Alberta:

- The BC Government has noted (see The BC Jobs Plan[173]) that LNG exports have the potential to replace coal-fired generation in China and other energy hungry countries, and that the BC Government is committed to working with LNG export proponents to bring at least one LNG pipeline and terminal online by 2015 and have three in operation by 2020, assuming all environmental and permitting applications are granted.

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

- BC LNG Export Co-operative has applied to the NEB for a 20 year export license for 1.8 million tonne LNG/year produced on a grounded barge at Kitimat starting in 2013[174]. The project is a 50/50 partnership between the LNG Partners (Houston) and the Haisla Nation Douglas Channel LNG Limited Partnership, and has arrangements to take advantage of unused capacity on the existing Pacific Northern Gas Pipeline.

- Royal Dutch Shell Plc is reported[175] to have filed for regulatory approval to build a small-scale LNG plant to produce 0.3 megatonnes per year at its existing Jumping Pound gas plant about 30 km west of Calgary. Work is expected to be completed by 2013. The project is to promote LNG as a transportation fuel (especially for trucks) in Alberta and eventually in BC.

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

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

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

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

Fort Nelson[176], pre-treat the gas to remove unwanted components (primarily water and CO_2) and then refrigerate the clean gas to LNG for transportation and supply. Gas supplies for LNG production in the Fort Nelson area are expected to be indexed to lower 48 pipeline gas cost (Henry Hub and NYMEX), which are expected to be at least $3 MMBTU lower than Kitimat-based LNG production that will be indexed to world LNG prices.

6.1.2 Background on LNG Opportunities in Yukon

Section 3.2 identified LNG as one of the potential near-term thermal resource options to be considered, noting (as with other near-term thermal options) that current pre-feasibility information on supply options is preliminary, particularly as regards to feedstock supply development or arrangements for use in Yukon. Trucked-in LNG is assumed as the supply source of Yukon LNG until local natural gas supplies are available – for initial costing, an LNG supply is assumed to be secured from facilities developed at Kitimat or at Fort Nelson, B.C., with the LNG then shipped to Whitehorse (for YEC grid power use), Watson Lake (for YECL utility generation) and potentially off-grid mine sites (for generation at each mine site). Finalizing the preferred sourcing of LNG fuel supply is a significant issue to be addressed if this option is pursued.

During the Charrette it was noted that due to the isolated nature of the Yukon grid and the potential for large industrial loads to come on and off the system, resource planning must ensure supply options are sufficiently flexible and robust to address the markedly different load scenarios that may exist on the grid from time to time. Changes in load may adversely impact grid diesel generation requirements and related GHG emissions, as well as the cost effectiveness and rate impacts for any capital intensive supply options pursued in the near-term. Similarly, new capital intensive renewable resource developments may create new increases in supply that need to be accommodated concurrently with changes in load. Finally, as reviewed in Section 2.4, flexible and reliable resource options with low capital costs will continue to play a key role on the Yukon hydro grid to address winter peak capacity as well as emergency reserve requirements, seasonal load/hydro supply fluctuations, and annual hydro supply fluctuations.

Subject to securing LNG supply (see Section 6.1.1), LNG/Natural Gas has been recognized as a reliable resource option for power generation that offers many of the same attributes as diesel generation, but at

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

lower overall cost than diesel and (at simple cycle operation) with 30 to 34% lower overall GHG emissions than diesel. Key related features include:

- Natural gas power plants are intended to be operated only when required and (subject to securing fuel supply) can be relatively easily integrated into the Yukon system as conversion or replacement of the current diesel generation plant. New equipment and retrofit of existing diesel engines can provide a range of options for LNG/natural gas use, including options for dual fuel (diesel/natural gas) operation.
- Natural gas power plants require relatively low capital costs, with options for scalable generation over a wide range of sizes, as well as options for combined cycle and cogeneration (with associated higher capital costs).
- Natural gas power plant operating costs are mostly composed of fuel cost that is subject to ongoing inflation and market price uncertainty.
- Natural gas power units can be permitted, purchased and installed within reasonably short time periods (i.e., usually well under 2 years) , as well as be reliably operated over an economic life of 20-25 years; units can also be located at load centres (minimize transmission requirements).

A gas co-generation facility installed in Whitehorse would also provide an opportunity for waste heat application, in much the same way (and for the same markets) as reviewed in Section 5 regarding the 2.2 MW WTE resource option.

As previously noted in Section 2.3, the developer of Casino mine has identified LNG as the preferred energy source to reduce costs related to this mine's future large-scale baseload power generation, [177] and the developer of the Northern Dancer mine[178] is also considering LNG as a source of supply. Use of LNG in a combined cycle power facility at the Casino project is expected to reduce costs at this mine site to within an 11-15 cents/kW.h range (versus the 30+ cents/kW.h range for diesel). Under this approach, Casino (as well as Northern Dancer) would also retain flexibility to further reduce operating costs by converting the power generation to natural gas when/if local natural gas becomes available (e.g., power generation costs estimated for Casino at <10 cents/kW.h with access to Alaska Highway Pipeline Project natural gas).

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[177] The Casino mine developers (Western Copper and Gold) currently plan to secure LNG by truck and/or ship/truck from Kitimat or to secure LNG from a new LNG facility at Fort Nelson, BC. The Casino mine is expected to have a large scale power requirement starting in 2018 of 130 MW and 940 GW.h/year potentially sustained over several decades.
[178] With a power requirement of 30-35 MW (200 to 300 GW.h/year) for up to 30 years, potentially starting by 2017.

Based on the preliminary analysis to date, Yukon Energy has participated with Western Copper and Gold retaining Braemar Wavespec and Berger ABAM to evaluate the LNG & Natural Gas supply chain in lieu of diesel for electrical power generation fuel at the proposed Casino mine and process facility starting in 2018, and at Yukon Energy facilities at Whitehorse and YECL facilities at Watson Lake potentially starting in 2014 as well as at other off-grid existing and potential mine facilities (Wolverine, Selwyn and Coffee Creek were assumed for this purpose). The Braemar Wavespec studies are considering potential LNG supply chain options to secure LNG by trucking from either the proposed Kitimat LNG new facility at Kitimat BC or from pipeline gas at Fort Nelson BC[179] to reduce costs and emissions in Yukon by using LNG to displace diesel generation. Preliminary conclusions from studies to date include the following (see Figure 6-1):

- Under assumed diesel and natural gas price conditions (e.g., LNG cost at $9/MMBTU at Kitimat, natural gas cost at $6/MMBTU at Fort Nelson, and diesel fuel cost at $26/MMBTU or 89 cents/ litre), an LNG supply chain from either Kitimat or Fort Nelson is more cost effective than diesel for the various Yukon power generation use options and locations examined:
    - At lower supply level requirements typical of utility diesel power generation requirements (e.g., Scenario A or B for the grid diesel generation in 2015 as per the 2011 Resource Plan plus YECL Watson Lake diesel generation), including full consideration of grid diesel load fluctuations due to hydro generation seasonal and annual water flow fluctuations[180], LNG supply from Kitimat LNG tends to have better project economics for delivered LNG unit cost compared to Fort Nelson LNG (reflecting lower capital cost requirements for the option using an assumed Kitimat LNG export facility [rather than a new Yukon-dedicated LNG liquefaction facility at Fort Nelson] offsetting longer truck distances and higher gas-equivalent prices).
        - Estimated unit power generation costs[181] with simple cycle generation range from 17.0 cents/KW.h (Scenario A) to 15.7 cents/kW.h (Scenario B) with supply

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

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

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

from Kitimat - in contrast, with supply from Fort Nelson the estimated unit costs range from 17.9 cents/kW.h (Scenario A) to 15.8 cents/ kW,h (Scenario B).

  - Estimated unit power generation cost with combined cycle generation is lower than with simple cycle generation (15.6 to 14.2 cents/kW.h with Kitimat supply and 16.4 to 14.2 cents per kW.h with Fort Nelson supply).
  - Capital cost requirements are lower with the Kitimat supply option than with the Fort Nelson supply option (e.g., for the assumed Scenario A grid plus Watson Lake diesel displacement loads and combined cycle power generation), estimated capital costs for the LNG supply chain (excluding costs for new generating units) range from approximately $13 million for the Kitimat option to approximately $37 million for the Fort Nelson option (of which liquefaction facility costs approximate $26 million).

- LNG supply chain economics improve if additional LNG deliveries for off-grid mine power generation are assumed (beyond YEC and YECL loads assumed above). With the higher and more steady state load profile, Fort Nelson with new LNG facility costs dedicated only to Yukon loads has lower estimated delivered costs than LNG purchases from a Kitimat LNG export facility.
  - This conclusion applies with or without the Casino mine (although higher loads with the Casino mine tend to result in lower overall average supply chain costs per MMBTU than cases without the Casino mine load, notwithstanding impacts on increasing overall average trucking distance).
  - Combined cycle generation continues to offer cost savings compared to simple cycle generation.

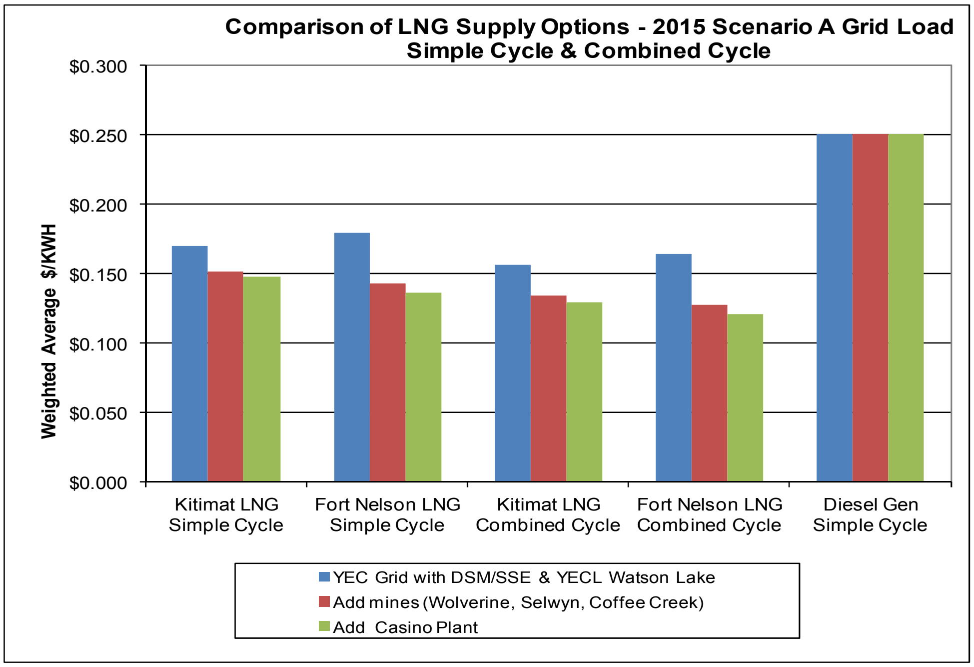
- Overall, increases in the LNG supply chain load requirement act to maintain and improve supply chain economics; delivered unit cost with all users examined is lower than would occur with only utility grid and Watson Lake loads. With appropriate planning, supply chain additions are very scalable through addition of added trucking units and liquefaction trains. There are a number of processes for small and mid-sized LNG liquefiers from a number of vendors who produce turnkey solutions.

- The cost of gas from Fort Nelson will likely sustain a lower unit cost than reliance on an LNG export facility at Kitimat overtime; trucking distances are also considerably reduced under the Fort Nelson supply option compared with the Kitimat supply option. Although not reviewed in detail, an Eagle Plains commercial gas supply would enable reduced LNG trucking distances on average for the Yukon loads considered.

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

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

Figure 6-1: Comparison of LNG Supply Options (Kitimat & Fort Nelson) with Diesel



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

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

6.1.3 Assumed Near-term Resource Options

As part of the 2011 Resource Plan, LNG is initially examined as a near-term and flexible supply option that could potentially be available as early as late 2014[182]. For simplicity, LNG/natural gas options are assumed to be developed at a scale sufficient to displace all grid diesel generation forecast under each load scenario. Cost estimates for LNG conversion, trucking and related costs are assumed based on the Braemar Wavespec studies to date and are considered adequate for initial pre-feasibility assessments. If the LNG option is to be pursued for near-term development for power generation in Yukon by late 2014, immediate further feasibility work will be required to determine the optimum way to secure the LNG, the required timing and all related costs.

In developing LNG Transition Portfolio Options, the following development approach was considered as regards Scenario A or B grid loads:

- A 20-30 MW LNG/natural gas power plant at Whitehorse (scale considered necessary to displace diesel under near-term loads with mines connected to the grid as assumed in Scenario A and B load forecasts).
    - Natural gas power plant scales required to displace all diesel generation requirements are assumed for this initial analysis at 22 MW for Scenario A loads and 30 MW for Scenario B loads[183]. Base Case load plant scales are assumed at 4 MW with DSM/SSE and 8 MW with no DSM/SSE.
    - Given these assumed plant scales, average annual plant capacity factors in 2015 with DSM/SSE approximate 44% for Scenario A and 54% for Scenario B. (Without DSM/SSE, these capacity factors are 51% with Scenario A and 60% with Scenario B).

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[182] The schedule required to secure the necessary LNG facilities and arrangements in time for potential in-service in late 2014 assumes that long-lead equipment orders would likely need to be placed in spring 2013 with actual construction/installation starting in spring/summer 2014. Pre-feasibility and feasibility assessments, along with related arrangements for securing LNG supplies, would accordingly likely need to be completed well before the end of 2012.

[183] Under either Scenario A or B, LNG thermal plant operation to displace diesel generation will typically be concentrated almost entirely in seven months (November to May); however, as noted in the Attachment E2 review of the diesel option, off-peak and summer generation is expected to be used during extreme low water years in order to meet non-hydro generation requirements with the available non-hydro plant capacity. Under an extreme low water year (average of load years) for the 2015 load forecast with DSM/SSE the annual capacity factor would approximate 79% for Scenario A (with 22 MW) and 81% for Scenario B (with 30 MW) - these capacity factors would increase to 87% with the 2015 grid load for each scenario without DSM/SSE.

- Simple cycle new gas turbines or internal combustion units are assumed with a 20 year life and a capital cost ($2010) of $1.5 million per MW; natural gas heat rate for the simple cycle units is assumed at 8.204 Mcf per MW.h (40% efficiency).
- Combined cycle units are also examined with a 20 year life and a capital cost ($2010) of $1.83 million per MW; natural gas heat rate for the combined cycle units is assumed at 6.562 Mcf per MW.h (50% efficiency).
- Non-fuel O&M costs for power generation assumed at $15 per MW.h plus fixed cost of $2.5 per kW.
- Natural gas prices ($2010) are assumed at $5.5 per MMBTU in 2015, increasing to $6.60 per MMBTU in 2020 and $7.45 per MMBTU in 2030[184]. After inflation assumed at 2% per year, these natural gas prices equal $6.07 per MMBTU in 2015, $8.05 per MMBTU in 2020 and $11.07 per MMBTU in 2030[185].

- The LNG resource option assessment assumes that YEC would source supply from a third party through a contract arrangement (rather than itself develop an LNG processing plant or provide the relevant trucking and other LNG-related supply chain facilities). For initial assessments (prior to more detailed review and optimization studies), the following options for LNG supply and trucking to Whitehorse are assumed (natural gas purchase costs are added to these based on the assumed gas requirements per MWh and assumed natural gas prices)[186].

    - **Fort Nelson area supply option:** A new small scale LNG plant established only for YEC loads with incremental costs for LNG conversion, trucking and related costs (e.g., truck

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

[185] See NRC natural gas price forecast showing strong agreement among industry experts regarding expected gradual rise in Henry Hub wholesale price over the period 2010 through 2015, 2020 and 2025 (forecast price [US$/MMBTU] with inflation approximates $6/MMBTU by 2015, approximately $8/MMBTU by 2020 and just under $10/MMBTU by 2025); (http://www.nrcan.gc.ca/eneene/sources/natnat/shocou-eng.php).

[186] Cost estimates based on the Braemar Wavespec studies to date adjusted to reflect the assumed peak scale of installed gas generation facilities (22 MW for Scenario A and 30 MW for Scenario B) and excluding gas generating plant (which is assumed to be owned and operated by YEC) and excluding costs related to LNG supply to Watson Lake or any other Yukon users, i.e., all costs assigned to YEC fuel supply. Capital related costs for LNG supply are treated as per the Braemar Wavespec study (annual charges based on 8% assumed cost of capital and economic life of 20 years).

loading/unloading facilities, storage at the power plant, a vaporizer or re-gasifier and all related indirect) assumed as follows ($2010):

- Simple cycle generation: 6.4 cents/ kW.h for Scenario A and 5.8 cents/ kW.h for Scenario B (capital costs of approximately $37 to $47 million (2010$) reflect 60% of these Scenario A costs and 53% of these Scenario B costs; liquefaction facility capital costs approximate $28 to $36 million of these capital costs).
- Combined cycle generation: 5.2 cents per kW.h Scenario A and 4.7 cents per kW.h for Scenario B (capital costs of approximately $30 to $38 million (2010$) reflect 60% of these Scenario A costs and 53% of these Scenario B costs; liquefaction facility capital costs approximate $22 to $29 million of these capital costs).

- **Kitimat area supply option:** supply from an LNG export facility with incremental costs for LNG purchase, trucking and related costs (e.g., truck loading/unloading facilities, storage at the power plant, a vaporizer or re-gasifier and all related indirect) assumed as follows ($2010):
  - An added cost for assumed gas purchase costs (above the assumed price at Fort Nelson) of $3 per MMBTU (2010$) to reflect LNG conversion costs and impact of export market pricing.
  - Simple cycle generation: 3.3 cents/ kW.h for all other supply costs for Scenario A and Scenario B (capital costs of approximately $10 to $13 million (2010$) reflect 31% of these Scenario A costs and 26% of these Scenario B costs).
  - Combined cycle generation: 2.7 cents/ kW.h for all other supply costs for Scenario A and Scenario B (capital costs of approximately $9 to $11 million (2010$) reflect 34% of these Scenario A costs and 27% of these Scenario B costs).

Figure 6-2 provides Forecast LCOE (2010$) for YEC grid generation with the above LNG supply options at Scenario A grid load with DSM/SSE and different sensitivity cases for extending mine load, for simple cycle and combined cycle generation with LNG supply from Fort Nelson and from Kitimat.

The following conclusions are noted:

- Combined cycle Forecast LCOE are consistently lower than simple cycle Forecast LCOE, notwithstanding the low annual utilization level (44%) assumed for average annual generation. Combined cycle Forecast LCOE for Scenario A with DSM/SSE are 19.0 cents/ kW.h for Fort Nelson LNG supply and 18.4 cents/ kW.h for Kitimat LNG supply.
- Kitimat LNG supply LCOE are consistently lower than Fort Nelson LNG supply LCOE (difference of 0.7 cents/kW.h for all simple cycle generation cases examined in Figure 6-2 and 0.6 cents per kW.h for combined cycle generation cases examined in Figure 6-2). This gap reflects the low average utilization assumed (which adversely impacts the much more capital intensive Fort Nelson LNG supply options) plus the absence of any other assumed loads to share in the assumed non-scalable portion of the Fort Nelson liquefaction plant capital cost (this portion represents 29% of the estimated liquefaction capital costs for the Scenario A load case, or about 0.84 cents/kW.h for the simple cycle option).
- LNG supply Forecast LCOE are 35-38% higher than Full Utilization LCOE for simple cycle options, and 52-53% higher than Full Utilization LCOE for combined cycle options. Seasonal and annual hydro fluctuations adversely impact LNG supply capacity average utilization and LCOE costs are adversely impacted to the extent that generation unit and LNG supply chain capital costs are underutilized. Full Utilization LCOE range from 13.7 to 14.5 cents/ kW.h for simple cycle options, and from 12 to 12.5 cents/ kW.h for combined cycle options[187].
- LNG supply Forecast LCOE are somewhat sensitive to extending mine loads after 2021 to 2025 and 2030 (the biggest sensitivity is an extension to 2025, reducing Forecast LCOE by 2.6 cents/kW.h for simple cycle options and by 3.2 cents/ kW.h for combined cycle options).

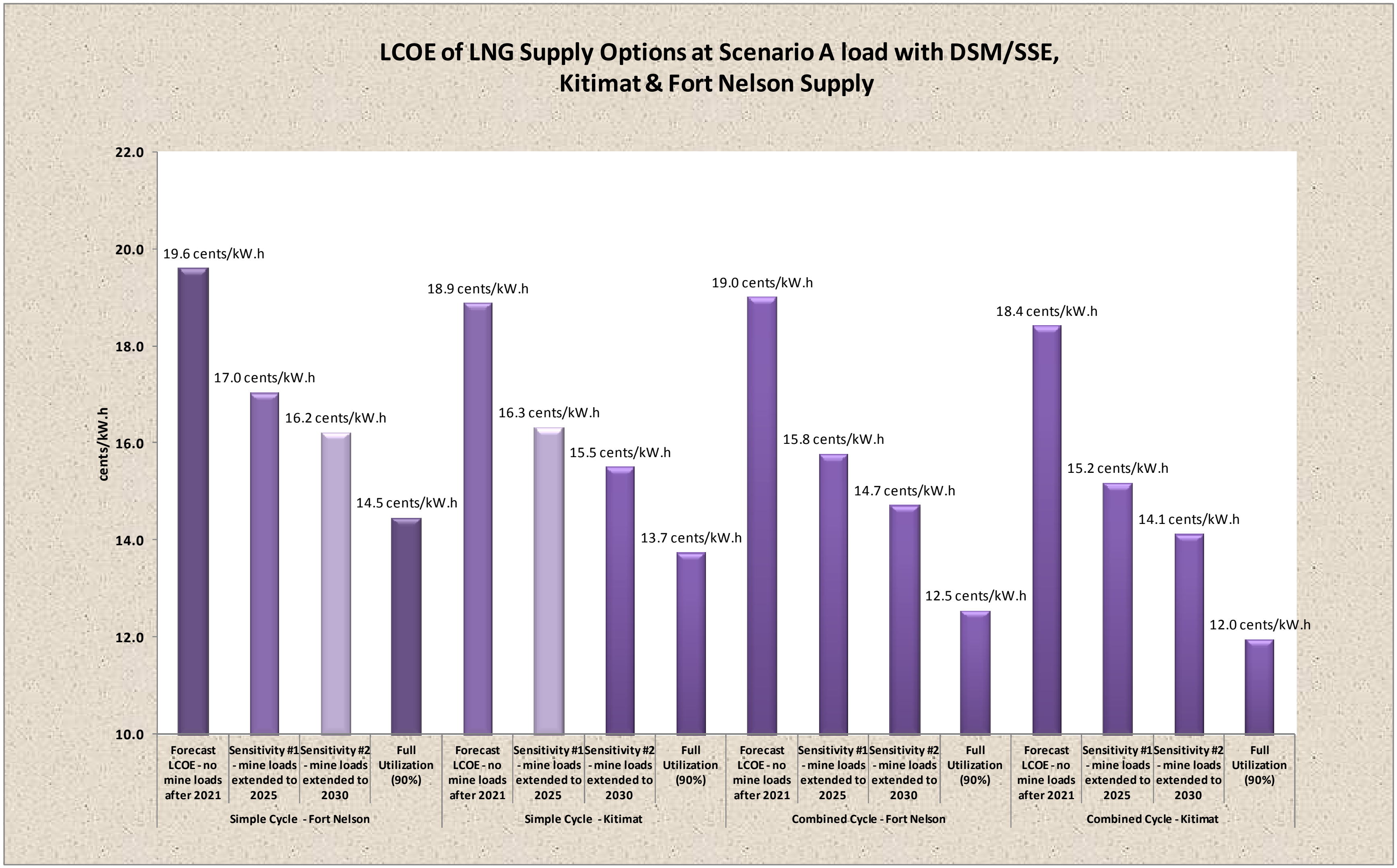
Based on the above analysis, LNG Transition Portfolio Options are assessed for the 2011 Resource Plan based on combined cycle generation for Scenario A and B loads (simple cycle is assumed to be all that is feasible for Base Case loads) with LNG supply costs for an assumed Kitimat area supply option.

[187] These LCOE are indicative of the cost savings relative to diesel that are potentially provided by LNG to off grid mine loads having high annual load factors.

Although Kitimat area LNG supply costs are used for assessments in the 2011 Resource Plan, it is recognized that the LCOE costs in Figure 6-2 fail to consider the implications of the broader LNG supply options for all Yukon loads. The Kitimat area provides an upper level near-term cost that a Fort Nelson area LNG supply option must not exceed; however, as demonstrated by the Braemar Wavespec studies, development of new LNG from the Fort Nelson area to supply various potential Yukon off-grid users as well as Yukon Energy grid use would likely provide lower LNG-based power costs for the grid and other Yukon users than reliance on the Kitimat LNG supply option. The Fort Nelson LNG supply option also offers lower long-term risks than the Kitimat LNG supply options as regards LNG-related fuel prices and shorter supply chain trucking distances to Yukon. Based on current information, securing LNG supply by late 2014 may also have greater likelihood of being feasible at Fort Nelson than at Kitimat.

The assumed use of combined cycle power units will provide the opportunity for waste heat sales for district heating in Whitehorse similar to such sales projected for wood biomass or WTE generation at Whitehorse (see Section 5). Based on potential district heat revenues examined in Section 5 (e.g., up to about $1.8 million per year), such sales could reduce Forecast LCOE costs by up to about 2 cents/ kW.h under Scenario A loads with DSM/SSE when mine loads remain connected to the grid. Given uncertainties regarding the life of connected mine loads and the sustainability of district heat supplied from LNG fuelled generation (which would be shutdown when grid loads do not require LNG generation due to surplus hydro generation), no district heat revenues are included at this time in the 2011 Resource Plan assessment of LNG supply options.

1 **Figure 6-2: Forecast LCOE (2010$) – Fort Nelson LNG Supply and Kitimat LNG Supply – Scenario A Load with DSM/SSE**



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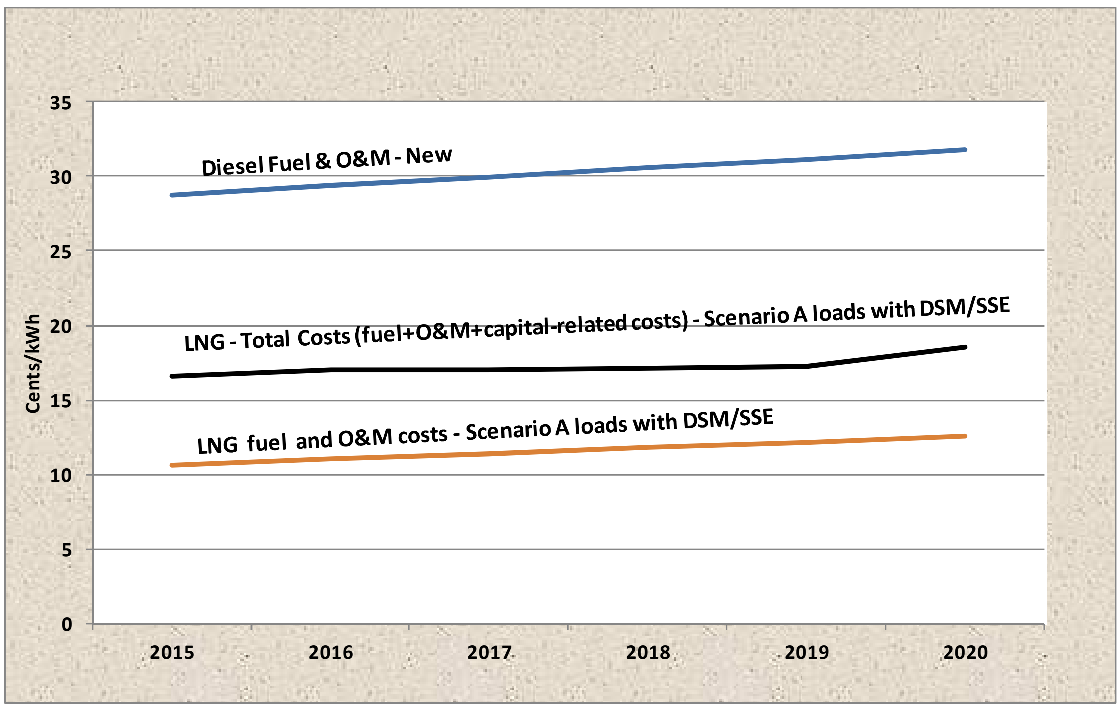
6.1.4 Near-Term Portfolio Options

The LNG/natural gas option as assessed for the LNG Transition Portfolio Options is similar to diesel in that it is fuel intensive with relatively low capital cost requirements - and accordingly provides flexibility in operation (i.e., it can be economically operated only when required to supply grid load).

Figure 6-3 shows costs per kW.h for new diesel plants and a 22 MW LNG/natural gas thermal plant during the brief period 2015-2020 under Scenario A load when the Victoria Gold mine load is assumed to be connected to the grid – in each year, diesel costs for fuel and O&M are well above the LNG/natural gas thermal plant costs (including capital as well as fuel and other O&M for the LNG power plant). Fuel and O&M costs account for 64% to 71% of LNG total annual costs in Figure 6-3 (capital costs in this analysis reflect YEC combined cycle generating unit capital costs).

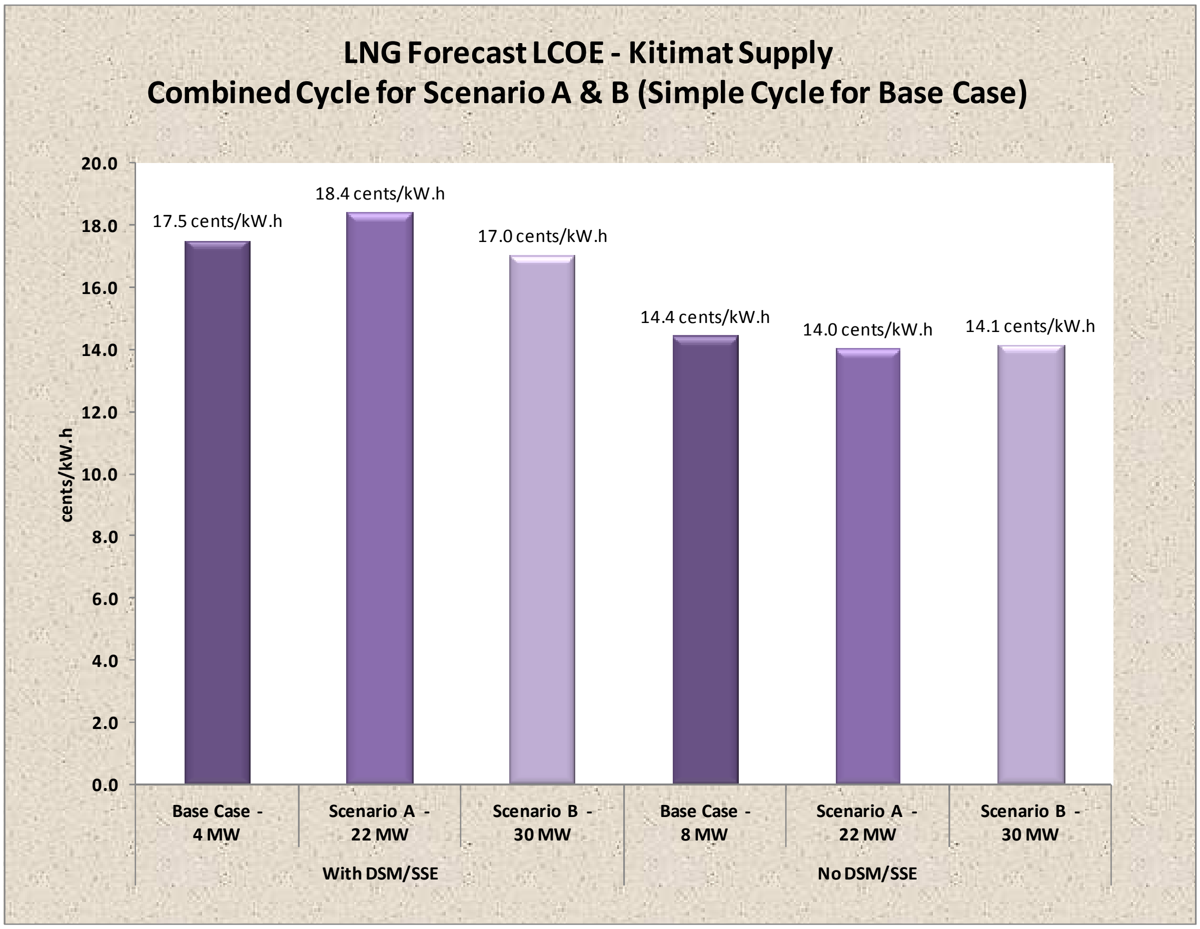
Figure 6-3: LNG Thermal Plant vs. Diesel Fuel & O&M Costs per kW.h – 2015-2020



Annual Cost (cents/kW.h)	2015	2016	2017	2018	2019	2020
Diesel Fuel & O&M - new	28.8	29.3	29.9	30.5	31.1	31.8
LNG - total costs - Scenario A (fuel, O&M and Capital-related)	16.6	17.0	17.1	17.1	17.2	18.6
LNG - fuel & O&M -Scenario A	10.6	11.0	11.4	11.8	12.2	12.6

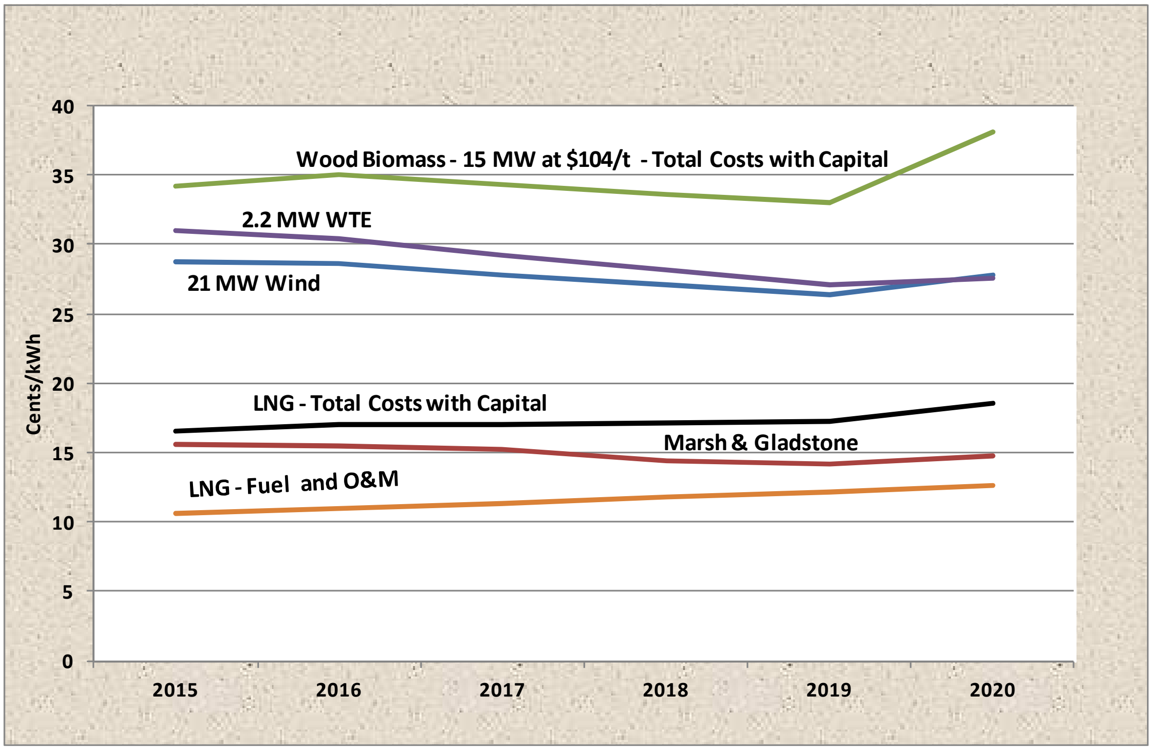
Reflecting the flexibility of the LNG option, Figure 6-4 shows that Forecast LCOE (2010$) over the assumed 20-year plant economic life remains relatively unchanged (i.e., between 14.0 cents and 18.4 cents/ kW.h) over a wide range of load scenarios (i.e., Base Case, Scenario A and Scenario B with and without DSM/SSE). The demonstrated variations in Forecast LCOE (and between Forecast LCOE and Full Utilization LCOE) reflect differences in annual plant capacity factors throughout the assumed plant life.

Figure 6-4: Forecast LCOE (2010$) for LNG Resource Option – Various Load Scenarios



In order to assess possible portfolio options with LNG that might be cost effective, Figure 6-5 compares annual costs for various resource options during the 2015-2020 period for Scenario A with DSM/SSE. Overall, LNG annual costs per kW.h during this period remain well below annual costs for all renewable resource options other than the Marsh Lake Storage and Gladstone Diversion hydro enhancements. Accordingly, LNG portfolio options eligible for review (beyond LNG on its own without any other resource options) include LNG with Marsh Lake Storage and LNG with the combination of Marsh Lake Storage & Gladstone Diversion.

Figure 6-5: Annual Costs per kW.h for LNG & Other Resource Options – 2015-2020



Annual Cost (cents/kW.h)	2015	2016	2017	2018	2019	2020
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

In summary, three near-term LNG Transition Portfolio Options are defined for further assessment (for each option, thermal plant size varies by load scenario with 4 MW for Base Case with DSM/SSE, 8 MW for Base Case with no DSM/SSE, 22 MW for Scenario A and 30 MW for Scenario B):

- LNG Transition Portfolio Option #1 - LNG on its own;
- LNG Transition Portfolio Option #2 – LNG and Marsh Lake Storage; and
- LNG Transition Portfolio Option #3 – LNG and Marsh Lake Storage & Gladstone Diversion.

Present Value Costs for each of these options are provided in Tables 6-1 (LNG Option #1), Table 6-2 (LNG Option #2), and Table 6-3 (LNG Option #3) - these costs are reviewed in Section 6.2. Each option is assumed to displace all Default Diesel Portfolio generation forecast each year after 2014.

Table 6-1: LNG (2015) LNG Transition Portfolio Option #1 (LNG on its own) Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only [5]
No DSM/SSE					
Base Case[4]	66.0	43.7		109.7	-54.9
Scenario A[4]	134.9	30.7		165.6	-117.9
Scenario B[4]	177.7	23.8		201.5	-162.2
With DSM/SSE					
Base Case[4]	23.6	31.9	35.4	90.9	-7.2
Scenario A[4]	98.1	11.4	35.4	145.0	-59.1
Scenario B[4]	139.6	5.2	35.4	180.2	-100.9

Notes:
1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. LNG estimates assume 4 MW for Base Case with DSM/SSE, 8 MW for Base Case w/o DSM/SSE, 22 MW for Scenario A and 30 MW for Scenario B.
5. See Diesel Portfolio Option Present Value Costs.

Table 6-2: LNG (2015) LNG Transition Portfolio Option #2 (LNG & Marsh Lake) Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only[5]
No DSM/SSE					
Base Case[4]	65.7	42.6		108.3	-56.3
Scenario A[4]	135.8	29.7		165.5	-118.0
Scenario B[4]	178.5	22.9		201.4	-162.3
With DSM/SSE					
Base Case[4]	26.9	26.6	35.4	88.9	-9.2
Scenario A[4]	101.5	10.6	35.4	147.6	-56.5
Scenario B[4]	142.7	4.5	35.4	182.7	-98.5

Notes:
1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Marsh Lake and LNG costs. Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. LNG estimates assume 4 MW for Base Case with DSM/SSE, 8 MW for Base Case w/o DSM/SSE, 22 MW for Scenario A and 30 MW for Scenario B.
5. See Diesel Portfolio Option Present Value Costs.

Table 6-3: LNG (2015) LNG Transition Portfolio Option #3 (LNG and Marsh & Gladstone) Present Value Costs: 2011-2030 (2010$million)

PV 2010$ million[1]	PV Energy Costs[2]	PV Capacity Capital Costs[3]	DSM/SSE Cost	Total PV Costs	Change from Diesel Only[5]
No DSM/SSE					
Base Case[4]	68.8	42.6		111.4	-53.2
Scenario A[4]	139.6	29.7		169.3	-114.1
Scenario B[4]	181.8	22.9		204.6	-159.1
With DSM/SSE					
Base Case[4]	44.9	26.6	35.4	107.0	8.9
Scenario A[4]	116.2	10.6	35.4	162.2	-41.8
Scenario B[4]	156.8	4.5	35.4	196.7	-84.4

Notes:
1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Marsh Lake, Gladstone Diversion and LNG costs. Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
3. Includes present value (2010$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. LNG estimates assume 4 MW for Base Case with DSM/SSE, 8 MW for Base Case w/o DSM/SSE, 22 MW for Scenario A and 30 MW for Scenario B.
5. See Diesel Portfolio Option Present Value Costs.

6.2 GRID ECONOMIC IMPACTS

As reviewed in Section 4.2, grid economic impacts for Portfolio Options are compared based on Portfolio present value (PV) costs and Forecast LCOE of non-diesel resource option package in each Portfolio. The following assessment focuses on the LNG Transition Portfolio, looking separately in each instance at grid economic impacts for Base Case load options and Scenario A and B load options. The analysis looks only at present value costs – Forecast LCOE assessment is not carried out given the flexibility of the LNG Transition Portfolio Options.

Present Value Costs

An overall present value cost assessment is provided for each LNG Transition Portfolio Option in Table 6-4 for Base Case loads as well as for Scenario A and B loads. The Default Diesel Portfolio is also shown for comparison. This assessment addresses total incremental generation costs during the planning period (2011-2030) under the relevant near-term grid load scenarios, showing outcomes both with DSM/SSE and no DSM/SSE. Default Diesel is assumed to be retained for 2011-2014 (before the LNG plant is established).

Table 6-4: Present Value Costs (2010$million) - LNG Transition Portfolio Options & Diesel

	Default Diesel Portfolio	Option #1 - LNG on its own	Option #2 - LNG and Marsh Lake Storage	Option #3 - LNG and Marsh Lake Storage & Glastone Diversion
Diesel Displaced 2015-2019[1]		100%	100%	100%
Present Value Costs (2010$million)				
No DSM/SSE				
Base Case	164.6	109.7	108.3	111.4
Scenario A	283.5	165.6	165.5	169.3
Scenario B	363.7	201.5	201.4	204.6
With DSM/SSE				
Base Case	98.1	90.9	88.9	107.0
Scenario A	204.0	145.0	147.6	162.2
Scenario B	281.2	180.2	182.7	196.7

1. LNG estimates assume 4 MW for Base Case with DSM/SSE, 8 MW for Base Case w/o DSM/SSE, 22 MW for Scenario A and 30 MW for Scenario B.

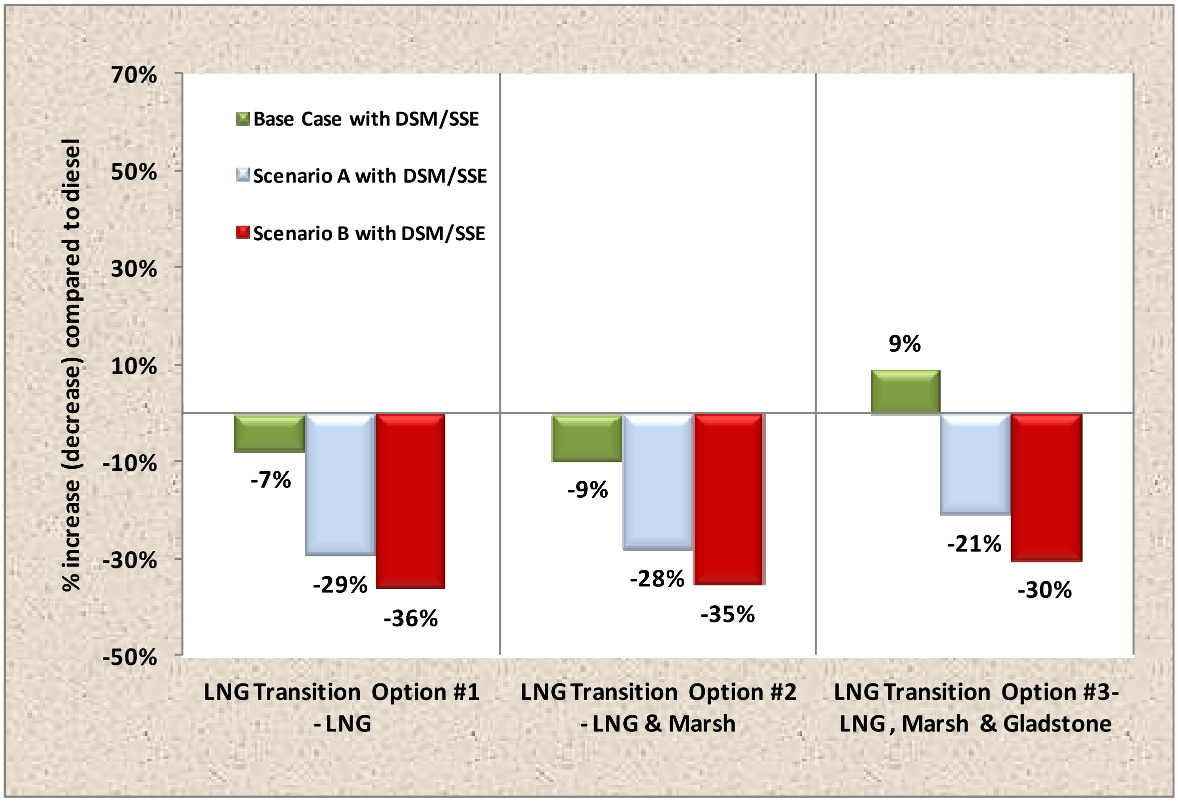
Figure 6-6 summarizes the percentage PV cost changes for the LNG Transition Portfolio Options compared to the Default Diesel Portfolio.

The LNG Transition Portfolio Option #1 (LNG on its own) yields 7% to 45% lower present value costs than the Default Diesel Portfolio, depending on the load scenario. Present value cost savings relative to the Default Diesel Portfolio for Scenarios A and B respectively range from $59 to $100 million with DSM/SSE (29% and 36% savings) and from $118 to $162 million with no DSM/SSE (42% to 45% savings).

LNG Transition Portfolio Option #2 (LNG & Marsh Lake) yields PV cost savings relative to diesel similar to Option #1. However, LNG Transition Portfolio Option #3 (LNG, Marsh & Gladstone) has higher PV costs than Options #1 and #2, and under Base Case load also has PV costs that are 9% higher than the Diesel Portfolio costs with DSM/SSE.

In summary, to the extent that LNG can be made available in Yukon it would appear that it could displace diesel as the default option. Similar to diesel, LNG offers flexibility – but in addition, based on current information, it also offers materially lower costs through a range of load conditions as demonstrated for the various load forecasts during the planning period. Furthermore, an LNG Transition Portfolio that includes Marsh Lake and (except for Base Case loads) Gladstone Diversion can continue to show PV costs savings relative to the Default Diesel Portfolio.

Figure 6-6: Change in PV Costs (%) LNG Transition Portfolio Options Compared to Default Diesel



6.3 YUKON GREENHOUSE GAS EMISSIONS IMPACT

LNG has lower overall GHG emissions than diesel generation, e.g., GHG for simple cycle operation with natural gas (LNG) at approximately 36% less than diesel fuel (about 451 tonnes per GW.h)[188]; and for combined cycle at approximately 48% less than diesel fuel (about 361 tonnes/kW.h[189]), regulated health air emission effects re: NOx, SO2 and particulates are also typically materially lower than diesel fuel emissions, with reduced potential concerns related to fuel spills effects (including storage tank leaks) compared with diesel fuel.

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[188] See Section 2 (footnote 59 and 60) for detailed calculation - the 36% estimate (and 451 tonnes GHG emissions per GW.h estimate) is calculated using emissions factor data provided in National Inventory Report and efficiency of 8.204 Mcf/MWh for simple cycle combustion.

[189] See Section 2 (footnote 59 and 60) for detailed calculation - the 48% estimate (and 361 tonnes GHG emissions per GWh estimate) is calculated using emissions factor data provided in National Inventory Report and an efficiency of 6.562 Mcf/MWh for combined cycle combustion.

Under all non-diesel resource options there is assumed to be no ability to displace diesel and GHG emissions until 2015 (as no potential resource options are assumed to be in service prior to that date).

GHG emissions reduction impacts from LNG Transition portfolio option #1 (LNG on its own) are estimated at 30% of diesel emissions displaced. LNG Transition portfolio options for loads that include additional generation from Marsh Lake Storage (Option #2) and Marsh Lake Storage & Gladstone Diversion (Option #3) would further reduce GHGs. Percentage GHG emissions under each option and load scenario with DSM/SSE are estimated as follows between 2015 and 2030:

- LNG Transition Portfolio Option #1 (LNG on its own):
    - Base Case (4 MW LNG using Simple Cycle) – Displaces 36% of Default Diesel grid GHG emissions.
    - Scenario A (22 MW LNG using Combined Cycle) – Displaces 48% of Default Diesel grid GHG emissions.
    - Scenario B (30 MW LNG using Combined Cycle) – Displaces 48% of Default Diesel grid GHG emissions.
- LNG Transition Portfolio Option #2 (LNG and Marsh):
    - Base Case (4 MW LNG using Simple Cycle) – Displaces 58-67% of Default Diesel grid GHG emissions during 2015-2020, and 69-100% of annual GHG emissions during 2021-2030.
    - Scenario A (22 MW LNG using Combined Cycle) – Displaces 52-53% of Default Diesel grid GHG emissions during 2015-2020, and 75-100% of annual GHG emissions during 2021-2030.
    - Scenario B (30 MW LNG using Combined Cycle) – Displaces 51% of Default Diesel grid GHG emissions during 2015-2020, and 75-100% of annual GHG emissions during 2021-2030.
- LNG Transition Portfolio Option #3 (LNG, Marsh and Gladstone):
    - Base Case (4 MW LNG using Simple Cycle) – Displaces 58-60% of Default Diesel grid GHG emissions during 2015-2017, 97-100% of annual GHG emissions during 2018-2020 (after Gladstone in service), and 100% of annual GHG emissions during 2021-2030.
    - Scenario A (22 MW LNG using Combined Cycle) – Displaces 52% of Default Diesel grid GHG emissions during 2015-2017, 69-72% of annual GHG emissions during 2018-2020 (after Gladstone in service), and 100% of annual GHG emissions during 2021-2030.

- Scenario B (30 MW LNG using Combined Cycle) – Displaces 51% of Default Diesel grid GHG emissions during 2015-2017, 62-64% of annual GHG emissions during 2018-2020 (after Gladstone in service), and 100% of annual GHG emissions during 2021-2030.

Overall, with equivalent hydro enhancements, GHG emissions reductions on the grid during 2015-2020 under LNG Transition Portfolio Option #3 would be less than would occur with Minimum GHG Emissions Portfolio Option A/B #3 (Marsh Lake Storage & Gladstone Diversion, and Wind), e.g., under Scenario A about 4,425 tonnes less emissions reduction in 2015, and (with Gladstone in service) 9,697 tonnes less emissions reduction in 2018.

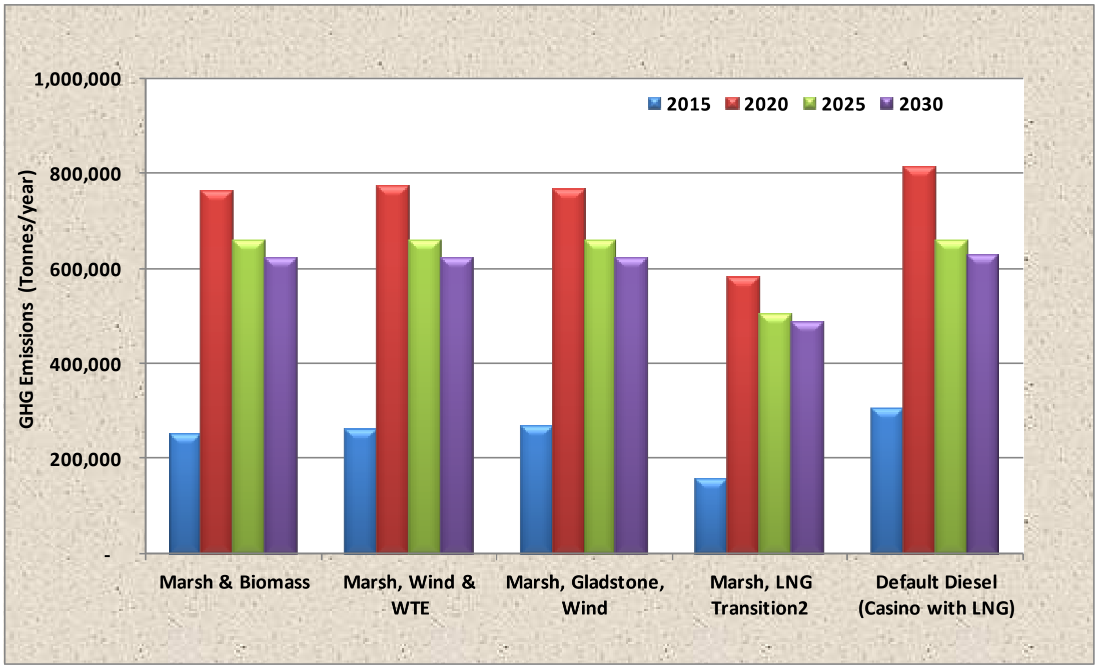
The above assessments consider only grid loads. As reviewed in Section 4.3, absent new LNG supply development it is expected that diesel generation for off-grid industrial loads will increase dramatically in the near-term if the many mine projects are developed as planned, increasing power-related GHG emissions in Yukon and changing perspectives as to the adequacy of relying only on DSM/SSE and non-diesel resource options related to utility customer grid loads. The Casino mine load's use of LNG, for example, would provide over 300,000 tonnes per year of GHG emission reductions relative to use of diesel in Yukon. Similar off-grid opportunities have not been identified for other resource supply options.

When off-grid industrial load opportunities are fully considered along with other potential LNG applications to displace oil fuel use, near-term LNG supply development in Yukon as part of the LNG Transition approach has the potential to achieve greater overall GHG emissions reduction than can be secured by the grid-focused Minimum GHG Emissions Portfolio Options reviewed in Section 5. For example, if (along with Marsh Lake Storage) use of LNG combined cycle generation in 2015 rather than diesel occurred for only 15 GW.h/year of the projected 352 GW.h/year of off-grid mine and utility loads (which exclude Casino), GHG emissions reduction in Yukon with LNG Transition Portfolio Option #2 and off-grid LNG use would exceed grid-based emissions reduction under Minimum GHG Emissions Portfolio Options A/B #2, #3 or #4.

In reality, the Braemar Wavespec studies and other available information indicate that LNG will likely be the preferred fuel source for onsite generation for all new off-grid mines using combined cycle units.

Figure 6-7 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 6-7: 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)[1]

	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[2]	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.

Introduction of LNG into the territory would also create opportunities to enable fuel switching (e.g., for use in vehicles on a territory wide basis and for heating applications in Whitehorse), helping establish additional ways to reduce overall Yukon GHG emissions. Such additional uses of LNG to displace oil fuel use in Yukon non-power generation sectors offer additional potential GHG emission reduction opportunities.

6.4 LONG-TERM DEVELOPMENT CONSIDERATIONS

LNG offers a near-term opportunity to materially reduce both costs and GHG emissions and can assist Yukoners through a transition period until such time as new legacy renewable supply resource options can be cost effectively pursued. In this way, LNG can be used to facilitate desired longer-term legacy resource development.

The LNG Transition Portfolio Option is designed as a potential transition response to current grid load forecasts and the impacts expected to be associated with the Default Diesel Portfolio as well as various Minimum GHG Emissions Portfolio Options relying on renewable resource development. LNG is not considered as a long-term legacy resource option for Yukon. The intent would remain to displace LNG use with appropriate renewable resource options when it is cost effective to do so (i.e., when sustained high utilization can be effectively achieved for renewable electricity generation options over most of their economic life so as to secure Forecast Utilization LCOEs that are equivalent to or less than LNG costs).

More specifically, LNG Transition Portfolio Options are expected to show escalating costs through future years as natural gas prices are expected to increase at a rate faster than general inflation. Although the precise timing and extent of such price increases is uncertain today, analysis in Section 5.4 indicates how by 2020 the initial year costs for a new hydro development might correspond to the then current costs for LNG-supplied generation - in which case, the transition from LNG to new hydro could occur relatively smoothly, subject to the overriding need for sustained long term load to appropriately utilize the new hydro on a sustainable basis.

At such time as new hydro develops, LNG 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[190].

As discussed in Section 5, and particularly in Section 5.4, longer-term development if feasible before 2021 of medium and/or large scale hydro options offer potential to establish sustainable lower cost electricity as well as low GHG emissions in a way similar to that secured by earlier legacy hydro developed in response to earlier major Yukon industrial mine developments. Near-term planning to protect such hydro development opportunities is outlined in Section 5.4. Near-term cost savings provided by an LNG Transition Portfolio could facilitate ability to proceed with such planning for the next major legacy renewable resource developments.

[190] 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 Plains 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.

6.5 CONCLUSIONS

The LNG Transition Portfolio Option is designed as a potential transition response to current grid load forecasts and the impacts expected to be associated with the Default Diesel Portfolio as well as various Minimum GHG Emissions Portfolio Options relying on renewable resource development. Near-term cost savings provided by an LNG Transition Portfolio could facilitate ability to proceed with such planning for the next major legacy renewable resource developments.

LNG is not considered as a long-term legacy resource option for Yukon. The intent remains to displace LNG use with appropriate renewable resource options such as greenfield hydro options discussed in Section 5.4 when it is cost effective to do so (i.e., when sustained high utilization can be effectively achieved for renewable electricity generation options over most of their economic life so as to secure Forecast Utilization LCOEs that are equivalent to or less than LNG costs). When developed, such legacy hydro projects will also further reduce GHG emissions and help to stabilize overall longer-term power costs in Yukon.

LNG thermal generation involves relatively low capital costs, and retains the flexibility and reliability that characterize the diesel thermal option. In effect, natural gas power plants are intended to be operated only when required and (subject to securing fuel supply) can be relatively easily integrated today into the Yukon system as conversion or replacement of the current diesel generation plant.

Under each of the assumed forecast load scenarios, the LNG Transition Portfolio Options provide over the 20-year planning period for materially lower present value (PV) costs than Default Diesel, as well as materially lower GHG emissions compared to diesel. In contrast, near-term capital intensive renewable resource portfolio options which minimize GHG emissions on the grid (Minimum GHG Portfolio Options) provide over the 20-year planning period for materially higher overall PV costs and annual cost compared to LNG options.

- **Under Base Case load scenarios with DSM/SSE**, LNG Transition portfolio options #1 (4 MW LNG) and #2 (4 MW with Marsh Lake Storage) typically provide from 2015 to 2030 for lower annual cost impacts than the Default Diesel Portfolio. Over the 20-year planning period, these LNG options provide 7-29% lower PV costs compared to the Default Diesel portfolio. In contrast, Minimum GHG option Base Case #1 (Marsh Lake Storage and Gladstone Diversion) provides 12% higher PV costs compared to Default Diesel.
    - Without DSM/SSE these LNG options maintain lower annual cost impacts compared to both Default Diesel and the Minimum GHG Portfolio Options.

- A PV cost assessment of options without DSM/SSE provides that while all options examined have PV cost savings compared to diesel, LNG-based portfolio options have materially greater cost savings compared to all other portfolio options.

- **Under either Scenario A or Scenario B loads with DSM/SSE**, including with Scenario A or B sensitivity tests for mine load extensions to 2025 or 2030 (with DSM/SSE or without DSM/SSE), LNG Transition Portfolio Options are the only options that provide material PV cost savings over the 20-year planning period compared to the Default Diesel Portfolio[191].
  - All three LNG Transition Portfolio Options over the period from 2015 to 2020 provide lower incremental annual cost impacts compared to the Default Diesel Portfolio.
  - After 2020, diesel combined with DSM/SSE has lower overall annual cost impacts compared to all other portfolio options - slightly lower than LNG and LNG with Marsh in 2015. Absent DSM/SSE, after 2020 all LNG Transition Portfolio Options have lower annual cost impacts compared to diesel.
  - Assessment of LNG with Marsh and Gladstone (LNG Transition Option #3) indicates that Gladstone at best makes little difference to PV costs and annual cost impacts when it is combined with LNG and Marsh, even with higher loads such as Scenario B[192].
    - Of the LNG Transition Portfolio Options, with Scenario A or B loads this option provides the lowest PV cost savings compared to diesel with or without DSM/SSE; however, the differences are relatively small if no DSM/SSE is assumed.
    - LNG with Marsh and Gladstone has higher annual cost impacts than other LNG Transition Options when mine loads are shut down with DSM/SSE.
    - With mine loads extended to 2025 or 2030, Gladstone with LNG and Marsh provides for generally the same overall PV cost savings compared to LNG with Marsh, both with and without DSM/SSE.

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[191] Under Scenario A loads, LNG Transition Portfolio Options #1 and #2 provide over the planning period between 23% and 24% PV cost savings compared to Default Diesel with DSM/SSE. Under Scenario B loads these LNG options provide 29-30% PV cost savings with DSM/SSE. In contrast, Minimum GHG Portfolio Options with Scenario A loads provide for PV cost increases compared to diesel with DSM/SSE in the range of 18% ($35 million for Option A/B #3 with Marsh, Gladstone and Wind) to 13% ($25 million for Option A/B#1 with Marsh and Wood biomass with no O&M cost after 2020 due to shut down of the wood biomass plant in response to the lack of connected mine loads). Slightly lower cost increases relative to Default Diesel occur for these Minimum GHG Portfolio Options with Scenario B loads with DSM/SSE, with the exception of a small PV cost saving ($4.4 million) shown for Option A/B#1 assuming no O&M cost after 2020.

[192] Gladstone in combination with LNG and Marsh provides for a 15% PV cost reduction compared to diesel under Scenario A loads with DSM/SSE and 24% PV cost reduction compared to diesel under Scenario B loads with DSM/SSE.

In summary, the LNG/natural gas option provides a range of benefits relative to the other available near-term grid generation options:

- Where established, LNG would displace diesel as the default option in Yukon (although dual fuel units could also cost effectively retain flexibility to use diesel if and when that would be advantageous). Lower cost LNG fuel would affect the assessment of future resource choices and also incremental pricing and rate setting in the rate zones where it is utilized (i.e., run out rates for higher use levels could be set based on LNG costs rather than diesel fuel costs).
- Other potential development benefits include:
  - LNG is the only option to offer material reductions in near-term annual cost impacts under Scenario A or B loads, as well as the non-diesel option with the lowest annual cost 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 29% under Scenario A and 36% under Scenario B).
  - Overall, this option offers high flexibility and ability to accommodate load changes; it can also be cost effectively developed concurrently with hydro enhancements such as Marsh Lake Storage and Gladstone Diversion.
  - The LNG Transition Option can accommodate optimum timing for Gladstone diversion, other potential hydro enhancements or greenfield developments, and wind development in response to confirmation of longer-term grid loads needed to secure reduced Forecast LCOE for these various renewable resource options.

Looking at GHG emissions reductions, LNG with combined cycle generation provides a 48% reduction in grid GHG emissions not otherwise displaced by concurrent near-term hydro projects such as Marsh Lake Storage and potentially Gladstone Diversion.

- Under Base Case Load scenarios during 2015-2019 LNG alone (Option #1) provides for a 36% reduction in grid GHG emissions, and the combination of LNG and Marsh (Option #2) provides for a 56-60% reduction (compared to a 35-38% reduction were only Marsh Lake pursued). If Gladstone can be committed with LNG and Marsh (Option #3), this portfolio option would increase the reduction in grid GHG emissions after 2017 to 97- 98% under Base Case loads with DSM/SSE.

- Under Scenario A or B loads with DSM/SSE the LNG Transition Option #2 (with Marsh) reduces grid GHG emissions during 2015-2019 by 51-52%. If Gladstone can be committed with LNG and Marsh (Option #3), the reduction in grid GHG emissions after 2017 increases to 69% with Scenario A and 62% with Scenario B.

LNG is the only portfolio option that can be used off-grid to reduce reliance on diesel (i.e., either off-grid communities or industrial customers). This option can also be used to reduce GHG emissions in other sectors where GHG emissions impacts are more significant (e.g., transportation). When off-grid industrial and community load opportunities are fully considered along with other potential LNG applications to displace diesel or other oil-based fuel use, near-term LNG supply development in Yukon as part of the LNG Transition approach has the potential to achieve far greater overall GHG emission reduction during the next 5-10 years than can be secured by grid-focused Minimum GHG Emissions Portfolio Options.

- Recent studies and other available information reviewed in Section 6.1 indicate that LNG will likely be the preferred fuel source for onsite generation for all new off-grid mines.

- Additional uses of LNG to displace oil fuel use in Yukon non-power generation sectors (e.g., transportation and heating) offers additional potential GHG emission reduction opportunities.

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

7.0 RESOURCE PLAN SUMMARY CONCLUSIONS

Yukon Energy's 2011 Resource Plan addresses updated generation and transmission priorities in Yukon for the 20-year planning period (2011-2030), focusing on resource planning options for implementation over the next five years (2011-2015).

Consistent with the 2006 Resource Plan, this planning level assessment is based on currently available information regarding forecast and potential energy and capacity requirements (Section 2) and available resource supply alternatives (Sections 3 to 6). Several planning stages are required after the 2011 Resource Plan prior to any YEC decision to proceed with construction for any preferred project.

Summary conclusions are provided for the following:

- Challenges and Opportunities;
- Forecast Yukon Requirements – Default Diesel Portfolio Option;
- Portfolio Options to Default Diesel; and
- Summary Conclusions and Next Steps.

7.1 CHALLENGES AND OPPORTUNITIES

Reflecting the March 2011 Charrette outcomes, the challenge for the 2011 Resource Plan is to determine how the forecast Yukon wide energy and capacity electricity requirements driven by economic growth can be turned into an opportunity during the planning period to create an enhanced supply of clean or sustainable energy that Yukoners can agree to and can afford.

- Higher costs to secure safe and reliable new resource supplies from utility operations on or off the grid will increase rates throughout Yukon.
- Higher greenhouse gas (GHG) emissions from increased electricity generation in Yukon, regardless as to whether these occur on or off the grid or derive from utility or non-utility operations, will challenge Yukon's ability to secure overall GHG emission reductions.
- Flexibility is needed in all circumstances to address the challenges related to the isolation of Yukon's electricity system, including challenges related to expected seasonal fluctuations in grid requirements for new generation, potential changes in connected mine and other grid 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.

To address this challenge, near and longer-term options are assessed concurrently 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[193], 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.

The 2011 Resource Plan confirms that forecast growth on and off-grid in Yukon will lead in the near as well as longer term to high costs and high GHG emissions during the 20-year planning period if diesel is relied upon to meet new generation requirements. The potential extent of new generation requirements in Yukon over the next decade is unprecedented – and highlights a resource planning requirement to address extensive rather than marginal new generation requirements.

Near-term grid generation resource portfolio options to diesel are identified for possible commitment before 2015. The near-term challenge is to move quickly to meet new grid requirements emerging today, while assessing the capability of new near-term resource portfolio options to meet the range of potential forecast energy and capacity requirements on the grid over the 20-year planning period (2011-2030).

Longer-term resource options throughout Yukon for potential start of construction before 2021 are also identified and examined in order to define appropriate planning activities during 2011-2015 to protect these options and to confirm that near-term portfolio options remain attractive after consideration of other longer-term resource options.

Overall, while near-term grid requirements and resource options define immediate challenges, the off-grid load growth and longer-term resource options define major opportunities in Yukon today.

7.2 FORECAST YUKON REQUIREMENTS – DEFAULT DIESEL PORTFOLIO OPTION

The 2011 Resource Plan recognizes diesel as the current default generation option in Yukon (i.e., the established and available supply option against which other new supply options must be assessed today for both on grid and off-grid power requirements beyond those that can be supplied by current and

[193] The four key planning principles agreed to by Charrette participants are reliability, affordability, flexibility and environmental responsibility.

committed hydro and wind renewable generation). Accordingly, the Default Diesel Portfolio option relies solely on established diesel generation capacity on and off the grid, and ability to secure easily new diesel capacity as required at relatively low capital costs, in order to provide reliable and flexible generation to meet all forecast electrical energy and capacity requirements beyond those that can be supplied by currently existing or committed hydro and wind generation[194].

Forecast Yukon Diesel Generation Requirements

The grid and off-grid diesel and other non-renewable generation load requirements define important elements of the GHG emissions and legacy resource development challenges to be addressed today for the 20-year planning period. Forecast Yukon diesel energy generation requirements under the Default Diesel Portfolio option for the 20-year 2011 Resource Plan planning period are summarized in Table 7-1.

Table 7-1 Forecast Yukon Diesel Energy Generation Requirements: 2011-2030
(Potential Off-Grid Mine Generation includes LNG & Diesel)

Diesel* Energy Requirement	2011	2015	2020	2025	2030
Base Case (GWh - Grid)					
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
Scenario A (GWh - Grid)	-	-	-	-	-
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
Scenario B (GWh - Grid)	-	-	-	-	-
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
Off Grid Diesel Community (GWh)	19.9	20.4	20.9	21.5	22.1
Potential Off Grid Mine Diesel* (GWh)	37.0	332.0	1,537.8	1,389.8	1,337.8

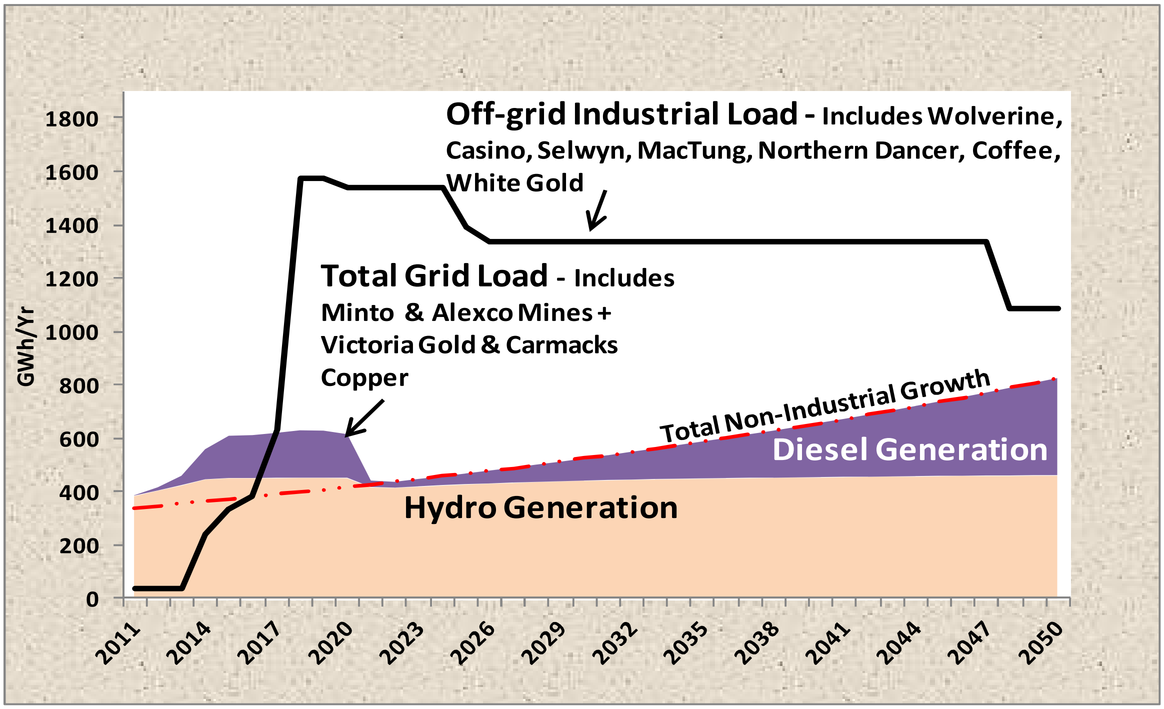
* Includes LNG for Casino mine

Figure 7-1 shows over a longer 40-year period (2011-2050) the existing Yukon grid system capability to supply potential grid load in the near-term (with Scenario B grid loads as shown in Table 7-1) and in the longer term with non-industrial grid load growing at an annual rate of 2.26% as assumed in the 2011 Resource Plan based on recent trends. Forecast grid diesel generation reflects the extent to which grid loads exceed long-term average generation from existing and committed grid hydro and wind generation.

[194] 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 7-1 also shows potential off-grid mine loads over the 40 year period, highlighting the potential extent to which mine load growth not connected to the grid could radically change Yukon power generation activities starting as soon as the 2015-2020 time period. As noted in Table 7-1, off-grid mine power generation is expected to rely upon diesel or LNG resource supply options.

Figure 7-1: Existing System Capability to Supply Potential Grid Load & Potential Off-Grid Mine Loads: 2011-2050



Forecast Grid Diesel Generation Requirements

Forecast utility grid (integrated WAF and MD grids) diesel generation requirements in Table 7-1 are provided for three grid scenarios focused on near-term (i.e., to 2015) mine load connection prospects[195].

- **Base Case** – Includes non-industrial loads growing at recent rates (2.26%/year) and current connected mines (Minto and Alexco – current forecasts assume these mines remain on grid until around 2020). With and without DSM/SSE, forecast Base Case diesel generation ranges as

[195] See Section 4, Figure 4-1 for summary of forecast diesel energy requirements [grid and off grid utility loads] and Figure 4-2 for new diesel grid capacity 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. 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.

follows: 15 to 24 GW.h/year in 2015, 9 to 32 GW.h/year in 2020, 2 to 41 GW.h/year in 2025 and 8 to 83 GW.h/year in 2030.

- **Scenario A** – Adds Victoria Gold mine to the grid Base Case in late 2013 (based on current 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 current information, forecasts assume on grid until 2021).
- **DSM/SSE** – Projections with no DSM/SSE and also with DSM/SSE (DSM/SSE assumed to secure a 67% reduction in annual non-industrial grid load growth each year starting in 2013)[196].

Over the 20-year planning period all existing Yukon Energy diesel generation capacity is forecast to be replaced due to expected retirements. The forecast timing for new diesel capacity is affected by the assumed capacity requirements during the 2013-2020 period related to different load scenarios[197].

Under all 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 40 GW.h to 80 GW.h per year under all "no DSM/SSE" scenarios that assume closure of connected mines after 2020).

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,

[196] 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 2011 after completion of current studies and program development). DSM is also being addressed with industrial customers and is anticipated to provide some loads 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 7.5 cents/ kW.h (2010$) of assumed energy load reduction.

[197] During the 2013-2020 period connected mine loads are expected to be sufficient to affect capacity planning requirements, while in other years the N-1 requirement based on non-industrial loads is expected to determine new default diesel capacity requirements.

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 Figure 7-1). Current forecasts indicate that industrial off-grid diesel and/or LNG power generation could potentially exceed 330 GW.h/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.

Flexibility Requirements Re: Connected Mine Loads

The 2011 Resource Plan forecast diesel scenarios focus on the hydro-based grid that serves most Yukon customers. Forecast Default Diesel Portfolio diesel energy requirements on the grid are driven by forecast future load growth, and this load growth is subject to considerable variability related to 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, and expansions or contractions in connected loads.

- Resource option sensitivity for displacing grid diesel generation is tested for different potential extensions of connected mine loads beyond the 2020 date after which current forecasts show shut down of connected mine loads (sensitivity is tested separately 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) is currently 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 Rau Gold, Ketza River and Brewery Creek), and at this time none of these mine loads have been included in current grid load forecasts.
- 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 in Figure 7-1. 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 Plains gas becomes available) that is currently planned to supply this load.

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 derives from the use of diesel fuel[198].

The cost challenge arising from the grid load forecasts is that grid Default Diesel Portfolio cost requirements even with DSM/SSE would, if realized, constitute a major rate driver starting as soon as late 2013 and continuing over the period to 2020.

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[198] 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.

While utility cost considerations and ratepayer impacts are focused on grid load default diesel generation requirements, considerations related to GHG emissions reductions in the power generation sector (whether utility generation or industrial on site generation) must consider the whole of Yukon.

Forecast grid generation accounts for a small portion of total GHG emissions forecast for the Yukon power generation sector[199]. 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 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.

In summary, the major near-term challenge for the next five years in particular based on the 2011 Resource Plan grid load forecasts is to reduce costs and GHG emissions by displacing diesel energy generation that would otherwise be required between 2014 and 2021. Assuming that the current Yukon mining boom is sustained, the very large longer-term challenge highlighted by the 2011 Resource Plan load forecasts is to secure long-term grid load growth beyond 2021 sufficient to achieve low cost and low GHG emission legacy energy supply project development.

7.3 PORTFOLIO OPTIONS TO DEFAULT DIESEL

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) non-diesel resource options in Yukon to cost-effectively reduce reliance on diesel generation and thereby also reduce GHG emissions from the power generation sector. Where relevant, non-diesel options are also examined to reduce reliance on diesel generation for the forecast off-grid loads summarized in Table 7-1.

As noted in Section 7.2, diesel displacement opportunities for grid loads have been examined in the 2011 Resource Plan with and without DSM/SSE programming that is assumed to commence by the start of 2013. Ongoing studies are defining the economic potential for DSM and SSE as well as specific programs

[199] See Figure 4-4 shows total Yukon non-renewable generation (grid and off grid) GHG emissions during the planning period under each grid load scenario with DSM/SSE (the table below the figure includes load scenarios with no DSM/SSE); the figure includes off grid utility communities and existing plus potential off grid industrial (mines).

and costs. Pending completion of these studies, the 2011 Resource Plan assumes that DSM/SSE will be implemented as a near-term major resource option, estimates potential limits as to how much diesel this option alone can displace under each load scenario, and tests the sensitivity of all non-diesel supply options to such potential DSM/SSE impacts. In summary, notwithstanding the materially higher diesel displacement opportunities (see Table 7-1) and higher Default Diesel Portfolio costs with no DSM/SSE (see Section 7.2), comparative 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[200].

Accordingly, the following summary analysis of portfolio options focuses solely on review of load scenarios with DSM/SSE.

Non-diesel resource options will be more effective in displacing diesel generation on the grid 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. 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)[201].

Overall, only a few non-diesel resource options that are currently or potentially feasible for consideration (e.g., hydro, LNG or future pipeline natural gas and, to a much lesser degree, wood biomass) offer large scale energy generation supply potential relative to forecast Yukon diesel generation loads. Portfolio options examine the extent to which different approaches 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.

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[200] 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 comparative annual cost impact penalties faced by non-flexible Minimum GHG Portfolio 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 and annual cost impacts over the planning period. However, the overall cost and annual cost impact rankings of LNG Transition Portfolio Options relative to Minimum GHG Portfolio Options or the Default Diesel Portfolio is not materially changed.

[201] See Section 2.4 for more detailed review of these material constraints and how they affect the cost-effectiveness and ability to utilize different generation resource options. 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).

Near-term Portfolio Options to Default Diesel

The 2011 Resource Plan identifies the following non-diesel resource options available for the grid that can be committed before 2015:

- Generation resource options identified as potentially available for in service by late 2014 include Marsh Lake Storage (6.4 GW.h/year potential), Wood Biomass Thermal (10 to 15 MW), Waste to Energy (WTE) Thermal (2.2 MW), Wind (10.5 or 21 MW), and Liquid Natural Gas (LNG) (4 to 30 MW). 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 options is assessed based on the information available at this time – recognizing that further feasibility work is required in each case to determine whether or not the option is feasible to be committed by the dates currently assumed.
    - Wood Biomass and LNG are options where sourcing fuel supply remains an issue to be addressed – further pre-feasibility analysis is required prior to relying on either of these options for near-term supply[202].
    - 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 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 examines 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.

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

[202] It is 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. Section 6.1 reviews 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, BC.

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 7-2 provides an overview of different resource portfolio near-term options indentified in the 2011 Resource Plan (Scenario A grid loads with DSM/SSE are assumed for this table[203]). 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 to be in operation by start of 2018]).

1. Minimum GHG Portfolio Options:
   a. Marsh Lake Storage & 15 MW Wood Biomass[204] (displaces 89-92% of grid diesel GHG for 2015-2019 period);
   b. Marsh Lake Storage, Gladstone Diversion & 21 MW Wind[205] (displaces 60-61% of grid diesel GHG for 2015-17 period and 84-85% for 2018-19 period [after Gladstone]); and
   c. Marsh Lake Storage, 21 MW Wind[206] & 2.2 MW Waste-to-Energy (WTE)[207] (displaces 70-74% of grid diesel GHG for 2015-2019 period).

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[203] 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.

[204] 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/ ODT. The plant is assumed to be shut down (no O&M cost) after connected mines are closed (after 2020).

[205] The Wind resource option assumes that, in addition to a 21 MW wind farm at Ferry Hill, 5 MW diesel rotary uninterruptible power (DRUPS) is required at a capital cost of approximately $10 million (2010$) for reliability if this level of wind resource is developed on the grid under forecast grid loads.

[206] Ibid.

[207] 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 $3.3 million per year (2010$).

2. LNG Transition Portfolio Options[208]:
    a. Marsh Lake Storage & LNG (22 MW) (displaces 52% of grid diesel GHG for 2015-2019 period); and
    b. LNG (22 MW) (displaces 48% of grid diesel GHG for 2015-2019 period).

Table 7-2 compares the present value incremental generation costs of each Portfolio option over the 20-year planning period as well as the Forecast LCOE (levelized cost of energy over project life)[209]. In summary, the following are noted:

- LNG Transition Portfolio Options have a much lower PV cost and Forecast LCOE than Default Diesel.
    - LNG Portfolio PV costs at 54% of PV costs for Default Diesel Portfolio under Scenario A with DSM/SSE.
    - LNG Forecast LCOE at 51-55% of Default Diesel Portfolio Forecast LCOE (61-66% if compare only with diesel fuel and O&M costs).
- LNG Transition Portfolio Options have a much lower PV cost and Forecast LCOE than any of the Minimum GHG Portfolio Options.
    - Minimum GHG Portfolio PV costs 119-147% of PV costs for Default Diesel Portfolio.
    - Minimum GHG Portfolio Forecast LCOE at 87-118% of Default Diesel Portfolio Forecast LCOE (104-141% if compare only with diesel fuel and O&M costs).

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[208] Assumes combined cycle generation units at Whitehorse with 50% energy efficiency (6.562 Mcf/MW.h) and that 22 MW capacity sufficient to displace all Scenario A forecast diesel generation (44% average annual plant capacity factor with 2015 grid load with DSM/SSE and average hydro generation). LNG supply assumed by truck from Kitimat LNG at cost of 2.7 cents/ kW.h (2010$) for all LNG supply costs other than LNG fuel (fuel cost at assumed BC natural gas price plus $3/MMBTU (2010$) to reflect conversion costs and impact of export market pricing; assumed BC natural gas price (2010$) at $5.5 per MMBTU in 2015 [$6.07 per MMBTU after inflation], $6.60 per MMBTU in 2020 [$8.05 MMBTU after inflation] and $7.45 per MMBTU in 2030 [$11.07 per MMBTU after inflation]). Although combined cycle will provide opportunity for waste heat sales in Whitehorse at least similar to those assumed for WTE option, no such sales revenues are currently included in the analysis (district heating sales equivalent to those assumed for 2.2 MW WTE would reduce 2 MW LNG costs by approximately 2 cents per kW.h); concerns about sustainability of district heat supplied from YEC LNG fuelled generation at forecast loads, i.e., LNG will be shut down when grid loads do not require LNG generation to displace diesel due to surplus hydro generation.

[209] 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 $35.4 million PV cost for DSM/SSE over this period, which is common to all Portfolio options. Forecast LCOE for a specific resource option is cents/ kW.h of forecast diesel displaced [2010$] over the assumed economic life of that resource option and assuming forecast diesel generation under Scenario A with DSM/SSE.

Table 7-2: Overview of Resource Portfolio Near-Term Options Scenario A with DSM/SSE: 2011-2030

	PV Cost million[1]	Forecast LCOE[2]	Capital Cost (2010$)		O&M Cost (2010$)		Reliable Capacity	Total Capacity	Energy Capability	Diesel Required/ Displaced
	(2010$)	c/kWh	$/MW	$million	$/MW.h	$mill./ year	MW	MW	GW.h/year	2015-19 av. GW.h/yr
Default Diesel Portfolio										
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	**168.6**	**36.1**								
Min GHG Portfolio Options										
Marsh & 15 MW Wood Biomass										
Marsh Lake Storage	7.0	**34.8**		10.5	-	0.1	1.0	1.0	6.7	6
Wood Biomass (15 MW)*	121.8		5.7	85.5	72.8	4.0	15.0	15.0	120.0	72
Diesel Energy	39.7				280.3				166.4	7
Diesel Capacity	16.5		1.5	31.6			21.1	21.1		
Total	**185.0**			127.6			37.1	37.1		
*No O&M after 2020										
Marsh, Gladstone & 21 MW Wind										
Marsh Lake Storage	7.0			10.5		0.1	1.0	1.0	6.7	6
Gladstone Diversion	20.8	**29.0**		40.0		0.2	-	-	36.6	NA
Wind (21 MW)*	88.4		3.6	93.4		2.1	5.0	26.0	55.6	45
Diesel Energy	57.1				280.3				245.3	NA
Diesel Capacity	27.3		1.5	46.6			31.1	31.1		
Total	**200.6**			190.5			37.1	58.1		
*Includes 5MW DRUPS										
Marsh, 21 MW Wind, & 2.2 MW WTE										
Marsh Lake Storage	7.0			10.5		0.1	1.0	1.0	6.4	6
Wind (21 MW)*	88.4	**39.4**	3.6	93.4		2.1	5.0	26.0	55.6	45
2.2 MW Waste to Energy (WTE)	25.9		17.7	39.0		(0.3)	2.2	2.2	17.1	14
Diesel Energy	56.7				280.3				228.0	20
Diesel Capacity	24.6		1.5	43.3			28.9	28.9		
Total	**202.6**			186.2			37.1	58.1		
*Includes 5MW DRUPS										
LNG Transition Portfolio Options										
Marsh & 22 MW LNG										
Marsh Lake Storage	7.0	**17.1**		10.5		0.1	1.0	1.0	6.4	6
LNG (22 MW)	65.4		1.8	40.3	95.6-107.9	0.1	22.0	22.0	173.4	79
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		
LNG (22 MW)										
LNG (22 MW)	69.0	**18.4**	1.8	40.3	95.6-107.9	0.1	22.0	22.0	173.4	85
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 all of the Minimum GHG resource options[210]. 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.

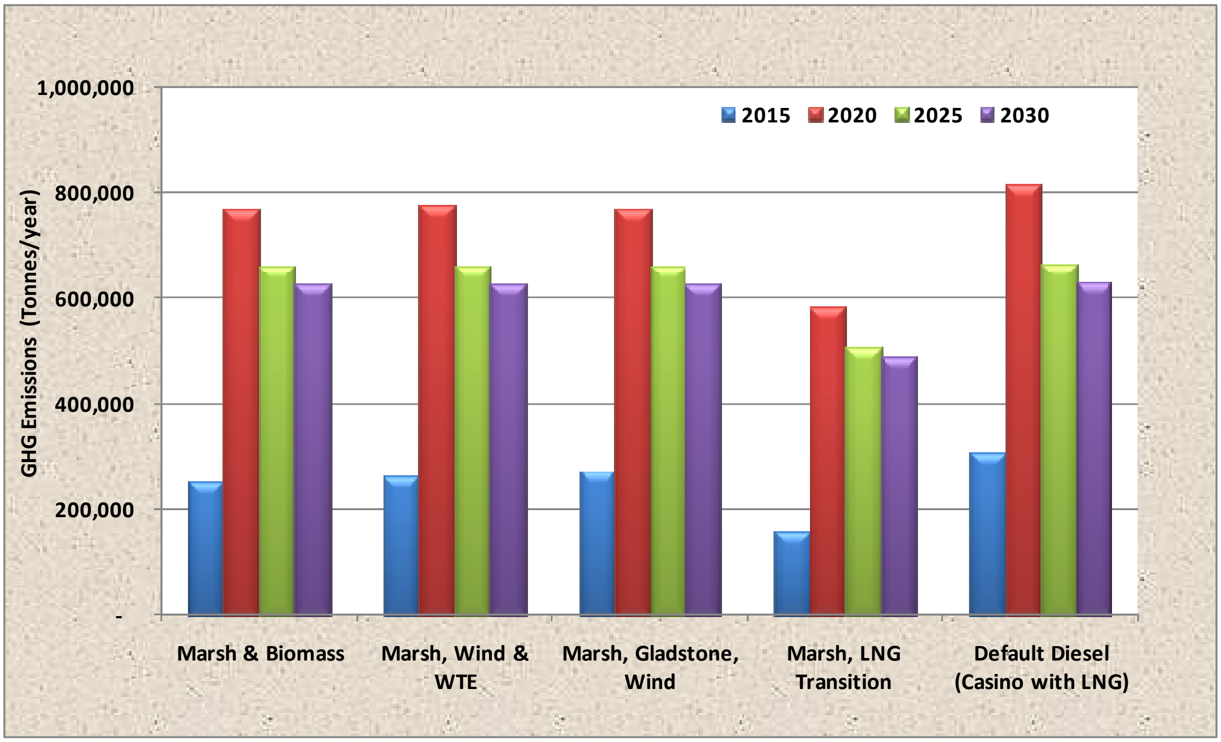
Among the near-term non-diesel resource options, LNG can provide flexible amounts of supply up to any load levels likely to be required and Wood Biomass can also provide relatively large amounts of annual generation (119.6 GW.h/year for a 15 MW plant)[211]. In contrast, maximum potential levels of annual 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).

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 7-2 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. Unlike other resource options, the LNG option can also be used to reduce GHG emissions in non-power generation sectors where GHG emissions impacts are more significant in Yukon (e.g., transportation).

[210] The Wood Biomass resource option is typically assumed to operate year round – however, this option is assumed to be flexible enough to shut down when the 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).

[211] Studies suggest that a 25 MW plant scale might also be feasible, with annual generation approaching 200 GW.h/year).

Figure 7-2: 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)[1]

	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[2]	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.

Longer-Term Resource Options to Default Diesel

Available long-term renewable resource options to reduce costs and GHG emissions consist primarily of greenfield hydro resource options potentially available to start construction before 2021 (some could potentially be in service before 2021), provided that sufficient site specific planning processes are sustained as required by Yukon Energy throughout the next five year period through 2015.[212] In contrast, longer-term direct access in Yukon to lower cost natural gas supplies for power generation is dependent upon development by others of the Alaska Highway Pipeline Project (in-service currently planned for 2020/21) and/or the Eagle Plains gas reserves – and the emergence of such supplies during the planning period would materially change the competitive context for a wide range of other resource options.

The potential extent of new off-grid generation requirements in Yukon over the next decade highlights resource planning opportunities to address extensive rather than marginal new legacy generation resource developments. Low cost (i.e., competitive with LNG or even natural gas, rather than only with diesel) and larger volume (hundreds of GW.h/year rather than tens of GW.h/ year) renewable resource options are required that can be developed within the next decade in response to these planning opportunities.

The greenfield hydro resource options identified as longer-term options are potential legacy projects that, subject to having adequate loads to fully utilize this generation, could provide relatively large amounts of lower cost power, e.g., total potential supply exceeding 6,800 GW.h/year at full utilization levelized cost (including transmission) below 15 cents/ kW.h[213].

- **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/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/ 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).

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[212] As reviewed in Section 3.1 and Section 5.1.2, geothermal and clean coal resource options are identified 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, indigenous Yukon coal resource development and evolving clean and small scale coal technology in other jurisdictions), the 2011 Resource Plan does not consider specific planning activities for these options during 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.

[213] See Section 5.1 and 5.4 for review of these longer term resource options and related planning requirements for the noted hydro project options. See Figure 1-2 and Figure 3-1 for maps showing the location of identified load and resource supply options. Other smaller hydro opportunities are also identified in these sections.

- **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/ 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.

Development of the lower cost and lower emission greenfield hydro generation options during the planning period 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.

The above off-grid mine and/or pipeline compressor loads are not being planned today 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 such new 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 Plains gas becomes available) that is currently planned to supply this load.

The LNG Transition portfolio option is designed as a potential transition response to current grid load forecasts and the impacts expected to be associated with the Default Diesel portfolio as well as various Minimum GHG emissions portfolio options relying on renewable resource development. LNG is not considered as a long-term legacy resource option for Yukon. The intent would remain to displace LNG use with appropriate renewable resource options when it is cost effective to do so (i.e., when sustained high utilization can be effectively achieved for renewable electricity generation options over most of their economic life so as to secure Forecast Utilization LCOEs that are equivalent to or less than LNG costs).

More specifically, LNG Transition portfolio options are expected to show escalating costs through future years as natural gas prices are expected to increase at a rate faster than general inflation. Although the precise timing and extent of such price increases is uncertain today, by 2020 the initial year costs for a new hydro development with a levelized cost (2010$) of 10 cents/kW.h might correspond to the then current costs for LNG-supplied generation - in which case, the transition from LNG to new hydro could occur relatively smoothly, subject to the overriding need for sustained long-term load to appropriately utilize the new hydro on a sustainable basis[214].

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[215].

If Yukon Energy is to protect opportunities to start construction before 2021 on any of the above hydro projects, considerable planning will be required through the next five years (2011-2015). Figure 7-3 provides an overview of the potential timing and key planning stages required to develop greenfield hydro project options during this period, highlighting actions needed during 2011-2015 to protect the ability to bring any such hydro option into service within the next decade and identifying currently identified potential off-grid load and development opportunities that are likely to affect hydro option planning.

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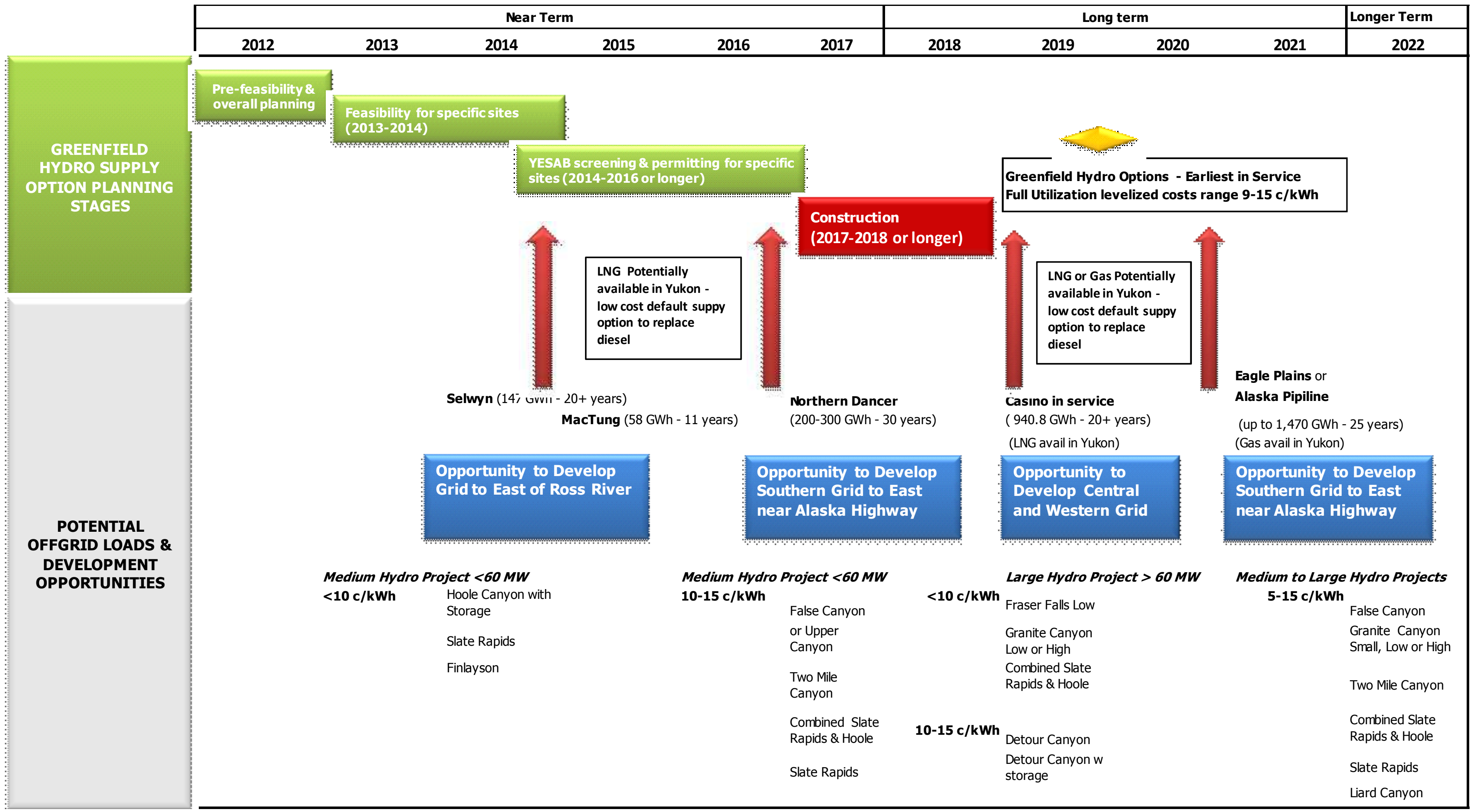
[214] Section 6, Figure 6-5 shows annual costs per kW.h during the period of forecast connected mine loads (2015-2020) for LNG fuel & O&M, LNG total cost with capital, Wood Biomass 15 MW option, 21 MW Wind, 2.2 MW WTE. Marsh & Gladstone. Overall, LNG annual costs (with capital) during this period remain 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 cents/kW.h (13 cents for fuel & O&M only).

[215] 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 Plains 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.

Figure 7-3: Overview of Planning Activities for Greenfield Hydro Supply Option Development - 2011-2021



7.4 SUMMARY CONCLUSIONS & NEXT STEPS

Looking beyond the next few years, the 2011 Resource Plan identifies a range of greenfield hydro resource project opportunities potentially available to start construction before 2021, subject to appropriate planning and development of loads sufficient to fully utilize these resources. These opportunities offer potential to establish sustainable lower cost electricity as well as low GHG emissions in a way similar to that secured by earlier legacy hydro developed in response to earlier major Yukon industrial mine developments. Near-term cost savings provided by an LNG Transition Portfolio could facilitate ability to proceed with such planning for the next major legacy renewable resource developments.

The LNG Transition portfolio option as described in the 2011 Resource Plan, if adopted for the near-term, is designed as a potential transition response to current grid load forecasts and the impacts expected to be associated with the Default Diesel Portfolio as well as various Minimum GHG emissions portfolio options relying on renewable resource development. LNG is not considered as a long-term legacy resource option for Yukon. The intent would remain to displace LNG use with appropriate renewable resource options when it is cost effective to do so (i.e., when sustained high utilization can be effectively achieved for renewable electricity generation options over most of their economic life so as to secure Forecast Utilization LCOEs that are equivalent to or less than LNG costs).

Development of such longer-term renewable resource options is subject to connecting new grid loads that could fully utilize the specific renewable resource options over 20-30 or more years. Protecting the option to start construction for such projects before 2021 is contingent upon sustaining sufficient site specific planning processes as required throughout the next five year period through 2015 (see Section 7.3). The 2011 Resource Plan 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- 10 years. These potential new loads offer the opportunity to plan on a coordinated basis for new legacy hydro development opportunities concurrent with actual development of new major mines or other major new loads. To protect the ability to proceed with such opportunities prior to 2021, the 2011 Resource Plan sets out proposed planning activities to be pursued during the next five to ten years (see Figure 7-5).

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

- Where established, LNG would displace diesel as the default option in Yukon (although dual fuel units could also cost effectively retain flexibility to use diesel if and when that would be advantageous). Lower cost LNG fuel would affect the assessment of future resource choices and also incremental pricing and rate setting in the rate zones where it is utilized (i.e., run out rates for higher use levels could be set based on LNG costs rather than diesel fuel costs).

- Other potential development benefits include:
    - LNG is the only option to offer material reductions in near-term rate increase impacts 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 23% under Scenario A and 29% under Scenario B).
    - Overall, this option offers high flexibility, and ability to accommodate load changes; it can also be cost effectively developed concurrently with hydro enhancements such as Marsh Lake Storage and Gladstone Diversion.
    - The LNG Transition Option can accommodate optimum timing for Gladstone diversion, other potential hydro enhancements or greenfield developments, and wind development in response to confirmation of longer-term grid loads needed to secure reduced Forecast LCOE for these various renewable resource options.
    - LNG is the only portfolio option that can be used off-grid to reduce reliance on diesel (i.e., off-grid communities such as Watson Lake and mines at various off-grid locations). This option can also be used to reduce GHG emissions in other sectors where GHG emissions impacts are more significant (e.g., transportation).

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

If fuel supply feasibility analysis determines that LNG cannot be available as a near-term option, the following are relevant to near-term resource planning:

- Default Diesel portfolio option is the least cost option under Base Case loads with DSM/SSE in the near-term, with lower percentage incremental annual cost increases over 2009 rates in almost all years compared to all Minimum GHG portfolio options considered.
- If diesel is not considered an option that can be relied upon under Base Case load scenarios due to environmental responsibility considerations, considerable caution would be appropriate in selecting a specific near-term alternative resource portfolio.
    - Marsh Lake Storage is a cost effective option under all load scenarios; however it is a relatively small project.
    - Going beyond Marsh Lake Storage and DSM/SSE, the remaining near-term renewable resource supply options each present challenges related to capital intensity and poor flexibility to deal with major drops in loads as is likely to occur after 2020 based on the best available current information. Gladstone Diversion is attractive if available in sufficient time to secure at least a few years of material cost savings; however, the appropriate timing for even this project option is clearly affected by the sustainability of mine-related loads connected to the grid.