YUKON ENERGY CORPORATION

20-YEAR RESOURCE PLAN: 2006-2025

January, 2006

and

SUPPLEMENTAL MATERIALS

May, 2006

SUMMARY OF PROPOSED ACTIONS

INTRODUCTION

Yukon Energy's 20 Year Resource Plan Submission addresses major electrical generation and transmission requirements in Yukon during the 2006 to 2025 period, with emphasis on:

a) near term projects that will require Yukon Energy commitments before the year 2009 with costs of $3 million or more, and
b) planning activities that Yukon Energy may be required to carry out in order to start construction on other projects before 2016 to meet the needs of potential major industrial customers or other major potential developments in Yukon.

In response to past commitments, the 20-Year Resource Plan Submission is expected to provide the Yukon Utilities Board (YUB) with the opportunity to review near term generation or transmission projects that Yukon Energy proposes to commit before 2009 with costs of $3 million or more, including projects based on revised planning criteria now adopted by Yukon Energy. The last Resource Plan, which was submitted for review by the YUB in 1992, covered 1992-2001 and was prepared by Yukon Energy and Yukon Electrical Company Limited (YECL).

The Submission also proposes Yukon Energy planning activities to protect Yukon Energy's ability to start construction on other major generation and transmission projects before 2016 to meet the needs of potential major industrial development opportunities.

This summary reviews the following:

- Resource Planning for Yukon Power Systems (to provide context for this Submission).
- New Capacity Criteria (reviews a key factor affecting proposed actions in this Submission).
- Proposed Near Term Actions (summary of actions proposed for commitment before 2009).
- Proposed Actions Relating to Industrial Development Scenarios and Opportunities (summary of proposed planning activities to protect possible commitments beyond 2009 and before 2016).

RESOURCE PLANNING FOR YUKON POWER SYSTEMS

The distinct and independent power systems in the Yukon are each served by separate source(s) of generation, and include: the Whitehorse Aishihik Faro (WAF) grid; the Mayo Dawson (MD) grid; the diesel community of Watson Lake; and a number of smaller isolated diesel communities (Beaver Creek, Destruction Bay, Pelly Crossing, Swift River and Old Crow).

Yukon Energy's generation on the WAF and MD systems accounts for 112.4 MW of the 127.4 MW of installed and currently rated capacity in Yukon. The YECL generation accounts for the balance, or for 15.0 MW of installed and rated capacity.

Yukon Energy's extensive hydro generation, as well as most of its related transmission facilities, were previously developed in response to major industrial mine developments. Today, these hydro systems are the key factor causing Yukon power costs to be lower than those found in Alaska or the Northwest Territories. Without such hydro facilities, Yukon utilities probably would have relied almost entirely on diesel generation with its associated higher costs.

The Yukon economy, and Yukon's electrical loads and systems have changed substantially since the 1992 Resource Plan review by the YUB. Highlights relevant to the current Resource Plan include:

- Due to closure of the Faro mine, no reopening of the UKHM mine, and no new mines yet having emerged on the WAF and MD systems, there is today a substantial surplus of hydro energy on these grids.
- Yukon Energy's response to these conditions has included greatly increased secondary sales and development of the Mayo Dawson Transmission Line.
- Yukon Energy's three water licences have been renewed.

As the major generator and transmitter of electrical power in the Yukon region, Yukon Energy plans for the capacity and energy requirements of Yukoners, particularly those supplied on the WAF and MD grids.

- **Capacity requirement** planning focuses on the highest or peak megawatt (MW) generation capability (capacity) required on each system during each year, including sufficient generation reserve capability (based on the system's capacity planning criteria) to address unplanned outages.
- **Energy requirement** planning focuses on the number of kilowatt hours (kW.h) of electricity that are required to be generated on each system.

The Resource Plan reviews WAF and MD system capability to supply loads today and into the future under various time horizons, industrial load development scenarios, and resource supply options.

- **Immediate need for new WAF generation capacity:** Forecast load growth, pending retirement (absent substantial Life Extension investment) of three Mirrlees diesel units (11.4 MW) located in YEC's Whitehorse diesel plant, and new capacity criteria adopted by Yukon Energy together create an immediate need for new WAF generation capacity to serve peak winter load requirements in the near term through to 2012.
- **Potential new mines prior to 2009:** Potential new industrial developments prior to 2009 at the Minto and Carmacks Copper mines may also absorb the WAF hydro energy surplus, support transmission extension of the WAF grid from Carmacks to at least Pelly Crossing, and create opportunity to interconnect the WAF and MD grids.
- **Diverse range of other possible industrial development scenarios and opportunities**: Planning activities to proceed with other energy-focused generation projects beyond 2009 and before 2016 are being driven by the potential needs of a diverse range of possible industrial development scenarios and opportunities, including various possible mines and the Alaska Highway Natural Gas Pipeline project.
- **Potential supply resource options for a construction start within the next 10 years**: Supply resource options potentially relevant for a construction start within the next 10 years vary widely depending on the potential industrial developments considered, and include a range of different hydro and diesel generation possibilities as well as transmission, and possibly coal and/or natural gas-fired generation.
- **Balance required**: Readiness and timing to supply new major industrial loads needs to be balanced with understanding of the long predevelopment timelines and considerable costs, uncertainties and risks associated with planning specific power resource options.

Varying levels of technical and costing assessments have been carried out to screen options, including in some instances investigations advanced to the project feasibility stage. The Resource Plan process identifies preferred projects for which YEC can then commit when appropriate to proceed with more detailed project-specific pre-decision planning.

This Submission includes near term projects at different stages of pre-decision planning. No final decision has yet been made to implement these projects. In some instances, environmental approvals have already been secured - in other instances, however, the necessary applications for such approvals have yet to be made. Final design, costing and tendering tend to be a final stage to be carried out prior to final Yukon Energy decisions to proceed with construction/implementation.

NEW CAPACITY CRITERIA

After an extensive review of its system capacity planning criteria, Yukon Energy has adopted new capacity planning criteria. System capacity planning criteria are the sets of rules used to determine how much generation is required on the various Yukon systems and when additions to generation capacity are required.[1]

Background on Evolution of Capacity Planning

Planning of a utility system must provide both for system growth and for operation after a component failure. Utility systems across North America vary greatly in size and complexity but the ability of each system to maintain service is compared by using established and recognized criteria.

The criteria used by the Northern Canada Power Commission (NCPC) prior to 1987 were developed to indicate the amount of firm generating capacity required to cover relatively small isolated systems, and were consistent with utility planning standards of that era. NCPC had started with a multiple of small isolated systems, some of which continued, but others had grown to the point where multiple sources were interconnected.

Yukon Energy (and its then manager, YECL), as the operator succeeding NCPC for the Yukon, initially followed the practice of NCPC. It was quickly found that the continuing small isolated installations were reasonably covered by the NCPC criteria but that the larger systems with multiple sources needed more detailed analysis to be secure:

- The small systems were considered to be adequately protected if the generating capacity with the largest single unit out of service was at least 110% of the anticipated peak load.
- For the larger "grid" systems, it became necessary to consider not only the possible loss of a single generator (in the case of WAF, a single "wheel" at Aishihik), but also the likelihood that at least one of the major WAF diesels would be unavailable at the same time. Consequently, the Resource Plan in 1992 introduced recognition of the diesel-related effect on Yukon Energy's ability to serve any particular WAF load by adding a "10% of installed diesel" reserve on top of the Aishihik hydro reserve.

Under the original NCPC capacity planning criteria and the capacity planning criteria reviewed in the 1992 Resource Plan, the transmission system availability was not taken into consideration.

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[1] For the purposes of system planning, all "firm" customer load requirements at the time of system maximum load or peak (e.g., winter peak on WAF) are considered when assessing each system's capacity planning requirements. Yukon Energy's policy requires that secondary energy service be interrupted when surplus hydro resources are not available, and therefore no bulk electrical supply capabilities are planned to supply secondary energy service.

In contrast to these earlier Yukon capacity planning criteria, integrated utilities today typically use a statistical approach to evaluate the potential interruption of service for any customer. This is often evaluated as the Loss of Load Expectation (LOLE) and it is measured in hours per year[2]. Most Canadian utilities apply an LOLE range from one to two hours per year as their capacity planning criteria standard. Further, where relevant, certain utilities today have incorporated transmission into this probability assessment when generation reliability is directly and materially affected by transmission.

Certain utilities have also adopted additional tests along with the LOLE criteria. For example, recently the Northwest Territories Power Corporation (NWT Power Corporation) has incorporated into its system capacity planning criteria a second test which is applied in parallel with LOLE criteria to ensure that customers are protected against failure of any single system component.

In summary, throughout various integrated utilities it is apparent that capacity planning criteria have evolved gradually into more defined ratios as systems have grown larger and more complicated. Furthermore, where relevant, transmission reliability is also being addressed today where it directly affects generation reliability.

Recent Yukon Energy Review of Capacity Planning Criteria

Yukon Energy recently completed an extensive review of its capacity planning criteria and, amongst other things, has examined the LOLE approach, testing it against the operating history of its WAF system. This review was undertaken in consultation with reliability experts from the University of Saskatchewan (under the direction of Dr. Roy Billinton[3]). Dr Billinton and his colleague were retained in late 2004 to review Yukon Energy's then established capacity planning criteria (i.e., the criteria as reviewed in the 1992 Resource Plan), including studying and determining the probabilities inherent in that criteria.

In contrast with statistical approaches such as LOLE, Yukon Energy's capacity criteria reviewed in the 1992 Resource Plan are "deterministic" in that a specific test was adopted for each system as a proxy intended to ensure adequate capacity. Yukon's criteria dealt with the concept of a "reserve" rather than actually assessing the likelihood (or probability) that the generation available will be insufficient to supply the load at any given point in time. Without reference to a specific probability of interruption, the adequacy of Yukon Energy's capacity criteria as reviewed in the 1992 Resource Plan cannot be readily compared today with criteria adopted in other jurisdictions for integrated systems.

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[2] Other terms are also used to describe the probabilistic measures, such as the BC Hydro criteria of Loss of Load Probability (LOLP) or Newfoundland and Labrador Hydro's Loss of Load Hours (LOLH).

[3] The same experts advised NWT Power Corporation in the development of the Snare-Yellowknife system planning criteria which criteria received approval from NWT Power Corporation and its regulator in 2004.

The recent work by Dr. Billinton addressed this issue with regard to WAF. It indicated that Yukon Energy's capacity criteria as reviewed in the 1992 Resource Plan provided excellent capacity reliability, based on LOLE, for residential and commercial WAF customers in 1996/97 when the Faro mine was operating. Today, however, in terms of the maximum peak load that can be supported, Dr. Billinton's work indicated that WAF generation is not adequate to supply the peak allowed under that same criteria within any reasonable LOLE reliability standard adopted elsewhere in Canada. The primary reasons for this conclusion are that the WAF system has substantial hydro generation availability that is directly affected by certain transmission, and further that 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).

As a result of this recent review, Yukon Energy has now 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.

At the same time, Yukon Energy has recognized that the LOLE function is an average that does not indicate how long any particular outage will last, and that any extended outage on WAF or the Mayo Dawson grid during the winter peak could be extremely serious for affected residential and commercial customers. Yukon Energy has addressed this concern by incorporating a second test as part of its capacity planning criteria, known as the N-1 standard[4] which ensures sufficient system capability to continue to serve firm residential and commercial customers when a failure occurs to the single largest system component. As an example, the biggest loss of generation on WAF today at winter peak would be 30 MW following a failure of the Aishihik transmission line; this loss would be far greater than the loss during winter peak of the biggest generator (which currently is a 15 MW generator at Aishihik).[5]

New Capacity Planning Criteria

The following new capacity planning criteria have been adopted by Yukon Energy:

1. **WAF and MD System-wide capacity planning criteria:** Each grid system (WAF and MD) will be planned not to exceed a Loss of Load Expectation (or LOLE) of 2 hours/year.
2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each grid system

[4] A test described as "surviving the first failure" or "operating in the N-1 condition where "N" is the normal system complement.

[5] The largest single unit on the WAF system today is WH 4, one of the hydro units at Whitehorse. However, as Whitehorse has 4 hydro units (WH1 at 5.8 MW, WH2 at 5.8 MW, WH3 at 8.4 MW and WH4 at 20 MW), but only 24 MW of firm flows in winter in drought conditions, a loss of WH4 would only effectively reduce the available capacity by 4 MW (as the other 3 units would still be available); this loss at winter peak would therefore be smaller than the loss of 15 MW via one of the units at Aishihik.

(WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source.

3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

For isolated diesel communities no change has been made for the capacity planning criteria (Yukon Energy will maintain the past criteria of being able to meet 110% of the community peak with the largest unit out of service).

PROPOSED NEAR TERM ACTIONS

Four separate major investments are proposed for Yukon Energy generation and transmission commitment before 2009, three with anticipated costs of $3 million or more. These proposed major projects will address near term requirements and opportunities to 2012 and together will provide over 21 MW of new WAF firm winter capacity by 2012 (i.e., enough new firm capacity to meet WAF capacity shortfalls that would otherwise be expected by 2012 of 18.7 MW under the Base Case forecast and 21.5 MW under the Base Case forecasts plus the Minto and Carmacks Copper mine loads). The four major proposed projects are reviewed below, along with contingency provisions and other proposed actions before 2012:

1. **Aishihik 3rd Turbine Project:** This project, which was initially reviewed in the 1992 YUB Resource Plan hearing, will provide 7 MW of added peaking capability[6] and about 5.4 GW.h/yr of long-term average hydro energy supply at the existing Aishihik generation station at a capital cost of about $7 million (2005$). Under Base Case loads without any new industrial developments, this project is expected to be economic within the planning period to 2025 based solely on its diesel operating cost saving benefits for the WAF grid, including displacement of peaking and then baseload diesel as WAF loads increase. Yukon Territorial Water Board and environmental approvals for the project were received in the new Aishihik Water Licence.
    a) Accordingly, this project will proceed with final planning activities to enable a final decision during 2007 to start construction for in-service by October 2009.

[6] Without twinning of the Aishihik Transmission Line, none of this added Aishihik capacity is recognized under the N-1 WAF capacity planning criteria, and only 0.6 MW is recognized under the LOLE WAF capacity planning criteria.

b) If Marsh Lake Fall/Winter Storage is developed without any additional non-industrial load growth or new industrial loads emerging, the final decision to start construction is proposed to be deferred until late 2009 for in-service in 2011 or 2012.

2. **Marsh Lake Fall / Winter Storage licence revision:** This project, which was not reviewed in the 1992 Resource Plan hearing, will increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and increase long-term average hydro energy from this facility by about 7.7 GW.h/year at a capital cost of no more than $1 million.[7] Yukon Energy will undertake the project planning activities, including consultation and environmental licensing, as required to seek amendment of the Whitehorse Rapids water licence to enable modified operation of Marsh Lake within its current lake levels to enhance fall/winter storage. Basically no new physical works are expected to be required for this project. Project approval is forecast by August 2007 (although provision is made in the event that the new Yukon environmental licencing regime requirements delays completion of the licence amendment to 2008). The effects of the proposed licence amendment are summarized as follows:

   a) **Remain within current lake level limits:** In all cases, the water levels with the amended licence will remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake).

   b) **Licence amendment changes the "controlled maximum" level:** The proposed amendment would change the licenced "controlled maximum" level that YEC can maintain upwards by about 1 foot; however, during uncontrolled periods of summer and fall (when YEC currently has no control over the lake and it is operating under an entirely natural regime), Marsh Lake has been known to peak at 2 feet above the YEC "controlled maximum" level. The effects of the proposed change are as follows depending on water conditions:

      i. **Non flood year operation other than a drought:** This project would allow Yukon Energy to reduce the amount of water it releases in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period. No effect is to occur under these conditions in any year prior to August 15, other than under drought conditions (see below).

      ii. **Flood year operation:** During flood years, there would be no change in the flood levels experienced on Marsh Lake, and no change to operations would be made during August and September until after flood levels subside.

      iii. **During drought years:** Current licence provisions to help alleviate summer drought levels on Marsh Lake through "early closures" of the Lewes Dam would

7 This estimated capital cost is made up of the costs for licencing, any required mitigation works and any potential facility modifications.

remain, and would likely be adapted to alleviate further summer drought conditions to ensure the lake reached the full supply capacity level in each year.

3. **Carmacks-Stewart Transmission Line Project:** This project will fully interconnect the MD and WAF grids as well as facilitate WAF transmission access to potential new mine loads at Minto and Carmacks Copper, providing 5.6 MW of additional firm near term capacity and 15 GW.h/year of additional near term energy for WAF[8]. Development of this project, which is estimated to cost about $35 million (2005$), is subject to provision of Yukon Government funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy. Based on external funding to assure no adverse impact on ratepayers from project development, planning activities will proceed with the Carmacks-Stewart project to enable a decision to proceed with construction early in 2007 for an in-service date in approximately late 2008.

4. **Mirrlees Life Extension Project**: Subject to confirmation of technical feasibility that is expected to be determined within the first quarter of 2006, the Mirrlees Life Extension Project will conclude final planning activities in 2006 in order to provide in-service during 2007 through to 2009 to provide an additional 14 MW of firm WAF winter capacity at a cost of up to $4.5 million (2005$).
   a) **First Mirrlees unit in service by October 2007:** By the summer of 2006 planning work and commitments for construction/implementation will begin on the first Mirrlees unit (5 MW) at a cost of up to $2.5 million (2005$)[9] in order that in-service will occur before October 2007.
   b) **Other two Mirrlees units by October 2008 and 2009**: Life Extension for the other two Mirrlees units will proceed thereafter for expected in-service in 2008 and 2009, subject to review of the experience gained from Life Extension of the first unit and the possible Yukon Energy consideration of replacing the third Mirrlees unit (4 MW) with a larger capacity new diesel unit (e.g., 8 MW or 11 MW unit).[10]

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[8] Added capacity and energy supplied to WAF by this interconnection are subject to MD loads, and will decline as MD loads increase. Reopening of the UKHM mine or other new industrial developments on MD, for example, would reduce MD surplus capacity and hydro energy available to WAF. In contrast, potential additional enhancements at the existing Mayo hydro facility or other new generation opportunities in the MD area could enhance overall WAF/MD power supply in the event of Carmacks-Stewart Transmission line development.

[9] This cost includes a “teardown” level of overhaul and the common diesel plant upgrade work necessary to undertake the Mirrrlees Life Extension Project.

[10] In the event that Mirrlees Life Extension proceeds but the Carmacks-Stewart Transmission Line is not developed in the near term, replacing the third Mirrlees unit with an 11 MW new diesel would more than replace the capacity that otherwise would have been provided by the Carmacks-Stewart Transmission Project.

5. **If Mirrlees Life Extension is not technically feasible, implement diesel replacement/expansion and/or other project options as appropriate:** Without the Mirrlees Life Extension option providing 14 MW of firm capacity, the key near term choice is between the option involving Whitehorse Diesel Replacement/Expansion (capability for three units with combined capacity of up to at least 33 MW) versus the Aishihik 2nd Transmission Line (providing 22 MW under N-1 criteria and about 14.4 MW with LOLE criteria).[11]

   Although the expected capacity shortfall can technically be met with the Aishihik-related option, this is not expected to be the lowest cost option to 2012 under Base Case loads and also this is not the lowest cost long-term option under higher loads including mines. The Aishihik-related option also exposes the WAF grid to near term and growing capacity shortfalls until it is completed.

   Accordingly, the Diesel Replacement/Expansion option will be implemented as follows in the event that Mirrlees Life Extension is not technically feasible[12]:

   a) **Base Case Loads**: **First Diesel Unit (8 to 11 MW) needs to be installed by October 2007:** Yukon Energy will need under these circumstances to proceed with final planning work on this project by summer 2006, including orders for the necessary engine unit (with cancellation provisions) in order that the unit can be installed by October 2007 at a capital cost (2005$) of up to about $7.2 million (8 MW) or $8.8 million (11 MW). This will include updating any common diesel plant systems necessary for connection of a new unit.
   b) **Other Diesel Units**: Once the first unit is committed, it is expected that up to two additional diesel units (depending on the unit size selected) will be implemented thereafter as required for in-service before 2012.

6. **Ongoing monitoring of existing customer load forecasts and new industrial development opportunities:** In order to facilitate ongoing assessment of generation and transmission options and requirements, Yukon Energy monitoring of annual customer class load trends (peak capacity and seasonal energy) on each grid is required. In addition, Yukon Energy will continue to monitor directly with developers and government specific new industrial

[11] In this context, the Aishihik-related option has been examined for possible implementation assuming that it is feasible to commit development of the Aishihik 2nd Transmission Line by 2009 at the latest; under this option, material near term capacity shortfalls would still occur until the Aishihik 2nd Transmission Line was in service.

[12] Diesel Replacement/Enhancement will also be the option pursued as required in the event that other major projects do not proceed as proposed, e.g., the Carmacks-Stewart Transmission Line Project (which is assumed to provide 5.6 MW by late 2008) and/or the Marsh Lake Fall/Winter Storage (which is assumed to provide 1.6 MW by fall 2007 or 2008). In the event that mine loads are connected to WAF without completion of the Carmacks-Stewart Transmission, Yukon Energy will review the feasibility of the Aishihik 2nd Transmission Line project.

development opportunities for grid power service, including assessment of any mine site power contribution to the supply of reliable grid peak capacity.

7. **Other Small Enhancement Projects:** Continued routine utility investment is recommended in assessing and proceeding with projects to enhance existing facilities at a cost less than $3 million. This includes:

   - study of the hydrology of the Southern Lakes, and potentially pursuing small water control structures in this region (new generating stations to manage water plus generate hydro power would, if proposed in the future, exceed $3 million);
   - continued pursuit of opportunities to cost-effectively rewind or re-runner existing hydro generating units at Whitehorse and Aishihik; and,
   - assessing need and timing for a potential 1 MW diesel unit installation at Carcross/Tagish (likely by YECL).

PROPOSED ACTIONS RELATING TO INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Yukon Energy proposes planning activities as set out below to address a wide range of potential industrial development scenarios beyond the near term, and to protect future opportunities to commit development of additional generation and transmission projects before 2016 in a timely and cost-effective way in the event that one or more of these industrial development scenarios materialize.

Planning activities are organized by industrial development load scenario, identifying proposals as to how to approach each load scenario should it arise. "Pre-commitment" activities are also addressed which encompass planning activities Yukon Energy proposes to carry out prior to any certainty or commitment on the part of potential new industrial loads.

Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario

This industrial development scenario (which provides for near term development and operation between 2007 and 2018 of the Minto and Carmacks Copper mines) supports commitment of modest existing hydro enhancements, but does not support commitment of any new hydro site development before 2016 unless mine loads of at least 10 MW are sustained well beyond 2016. Consideration of the smallest hydro site options (1-4 MW) could potentially be supported in the event that 10 MW mine load development extends through to at least 2020. In this context, the following planning activities are recommended in the event these mine loads are seriously being considered for development prior to 2016:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should then proceed to commit the Aishihik 3rd Turbine, the

Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments.

  - If not already committed, Aishihik Diversions and Atlin Storage should then be advanced to Level 2 studies, including system-wide water and load dispatch modeling, to quantify the energy benefits under this scenario.
  - Ongoing assessment of the Southern Lakes should be completed to identify additional water control or small hydro opportunities to enhance Whitehorse Rapids output.

- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission line is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility, including enhanced peaking capability.
- **New WAF hydro site development:** If industrial and overall load development commitment is such that both new capacity and baseload diesel generation energy are required through to at least 2020 (and there is no clear indication of more major industrial development scenarios emerging during the 20 year planning period), planning activities should be carried out to enable commitment of a very small hydro site development (1-4 MW, 5-30 GW.h/year) [13] able to provide new capacity and displace diesel energy.
  - Based on current information, this would indicate that the hydro site at Drury should at that time be advanced to full Level 3 studies that include consideration of variations that maximize capacity.
  - Possible consideration might also be given to Level 2 studies for Squanga as a utility project or IPP, and/or for Morley, as potential alternatives for comparison to Drury.
  - Consideration must include means to mitigate downside risks should industrial loads close prematurely.
  - Actual development in each or these cases will involve investments greater than $3 million, or long-term contract commitments in excess of $3 million present value to IPPs, and therefore YUB review will be sought prior to project commitment.
- **Other activities re: DSM:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused primarily on reduction of system peak demand.

Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 for development of more than 10 MW (70 GW.h/year) but less than about 20-25 MW (comparable to the Faro mine) for a period through to at least 2025, planning activities should be carried out to enable commitment before 2016 to develop new hydro site resources to provide approximately 50 GW.h per year to WAF.

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[13] Present estimates of the costs are $12-$47 million generation capital cost (2005$) with potential generation planning costs of $1.2-$4.7 million prior to a decision to proceed with construction.

For potential hydro projects, key options to be considered at such time as greater load certainty develops regarding this level and duration of industrial load are as follows:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should proceed to commit the Aishihik 3rd Turbine, the Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments (see proposals for Scenario 1).
- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility (including any feasible enhanced peaking capability).
- **New hydro site development:** If industrial and overall load development commitment on WAF before 2016 is such that WAF baseload diesel generation energy of more than 10 MW (70 GW.h/year) is then required through to at least 2025, and there is no clear indication of more major industrial development scenarios establishing new WAF industrial loads in excess of about 20 MW (about 125 GW.h/year) emerging during the 20 year planning period and extending beyond 2025, planning activities should then be carried out to enable commitment of a small hydro site development (7-10 MW, about 50 GW.h/year[14]) able to provide diesel displacing energy to WAF.
  - New hydro options focused on Yukon-based projects, if available, would be the preference.
  - However, given limited attractive projects in this size range identified in Yukon to date, further Level 1 and 2 activity should be undertaken if timing permits in areas within 50 km of existing 138 kV WAF transmission focused initially on scans of the various inventory studies completed by NCPC or others.
  - Sites in BC, including Moon Lake and Tutshi[15], should have Level 2 studies updated in preparation for this possible load scenario, particularly focusing on the costs and risks associated with interprovincial licencing requirements and water rentals. Level 3 studies should then proceed if warranted.
- **Coal supply possibilities:** In the event that the loads of this scale develop and coal also becomes available from developed Yukon sources, coal generation technology should be reviewed in the event that timing permits to determine the potential for an economic and environmentally sound coal development at sizes below 20 MW, sized as appropriate to fit the industrial loads being developed at that time.

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[14] Present estimates of the costs are \$50-\$100 million generation capital cost (2005\$) with potential generation planning costs of \$5-\$10 million prior to a decision to proceed with construction.

[15] No further work should proceed on Surprise Lake so long as the community continues its plans to develop micro-hydro at the site.

- **Other activities re: DSM and wind:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused on both the reduction of system peak demand and energy conservation, and development of new wind generation (if attractive sites near established utility grids can be identified).

Actual development of new hydro sites (or any other new generation site) in each case will involve investments greater than $3 million, so YUB review will be sought prior to project commitment. In addition, for larger scale developments, planning and feasibility work may exceed the $3 million level, so there is the potential for YUB review at this earlier stage as well.

Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 of more than about 20-25 MW (150 or more GW.h/year) for a period through to at least 2030, resulting in forecast baseload WAF diesel generation energy of more than about 150 GW.h/year to be required until at least 2030, then planning activities can reasonably proceed to consider commitments before 2016 to develop new hydro site or coal generation resources of 20-30 MW to provide 130-150 GW.h per year of long-term energy (20 or more years) to WAF.

- **Load uncertainties and low probabilities today:** The industrial loads required to reach the above levels at this time involve significant uncertainties and low probabilities.
- **New medium scale hydro site development (20-30 MW, 130-150 GW.h/year):** The development of generation and transmission to serve these loads, based on currently identified potential hydro sites (Primrose and Finlayson), would involve substantial generation capital costs ($179-$191 million (2005$)), excluding transmission, as well as very large planning costs (about $20 million) prior to a decision to proceed with construction. Such costs are likely at or beyond the limits of YEC's current financial capabilities and involve material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line.
- **Coal supply thermal generation possibilities:** Coal resource options of this scale could involve far less capital than comparable new hydro sites, provided that coal supply as such was otherwise available from developed Yukon sources. The scale at 20 MW (144 GW.h/year[16]), however, is still very small for coal thermal technology and would require careful Level 2 and 3 screening and feasibility assessments to confirm its potential feasibility.

For potential generation projects related to the above scales, it is not apparent today that there is sufficient likelihood of this major development scenario arising to justify major investment at this time in planning and

[16] The present estimate of the costs are $ 61 million thermal plant capital cost (2005$), excluding transmission or coal resource development costs, with potential generation planning costs of $6 million or more prior to a decision to proceed with construction.

feasibility studies for medium new hydro or small coal plants. Accordingly, no specific planning activities are recommended at this time.

Coal options for thermal generation must be environmentally sound to be considered. The feasibility of coal generation will depend in part on the cost of employing state of the art technologies to reduce emissions, as well as on the availability of coal supply from developed Yukon sources and the occurrence of very large industrial mine developments that can be connected economically to the grids.

Future decisions with respect to the level of effort and expense in this area will reflect YEC's ongoing assessment of the probabilities of the required loads developing. For projects of this scale, even early planning and feasibility work (at least on hydro sites) will exceed the $3 million level, in which case YUB review will be sought before proceeding with specific planning commitments of $3 million or more.

Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario

The Scenario 4 pipeline loads at this time involves significant uncertainties as regards timing and magnitudes. However, given the implications of this industrial development for all aspects of Yukon power utility activities, and its clear possibility to come into service within the 20-year period for the current Resource Plan, one key activity recommended for the near-term regarding Scenario 4 involves continued active monitoring of this development as well as active planning to identify and assess all potential related material impacts, options and opportunities, including:

- Power supply options for the pipeline for compression (focusing initially on short listing and assessing at Level 1 knowledge large scale hydro site options and related transmission requirements).
- More modest power supply opportunities focused on compressor station "station service" loads.
- Options to use natural gas for power generation to serve cost effectively other incremental industrial loads.

The development of generation and transmission to serve these pipeline loads is likely well beyond the limits of YEC's current financial capabilities, as well as involving material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line. Accordingly, prior to carrying out any planning activities beyond Level 1 assessment of any specific site or technology specific studies, it is proposed that Yukon Energy identify and assess options that would address this constraint, e.g., joint venturing with others, and/or options to secure external government or other financing.

Proposed "Pre-commitment" activities

Prior to any certainty developing regarding any specific industrial scenario that may arise, it is proposed that Yukon Energy remain focused on certain key planning activities to ensure protection of the options to address new load requirements. Yukon Energy proposes the following activities in this regard:

- **Monitoring of Industrial load developments:** Yukon Energy will continue to monitor closely potential load development and related spin-off residential and commercial impacts, including necessary discussions with mineral exploration companies active in Yukon, key officials in Yukon government working with mines and other industrial developments and relevant industry associations. Separately, YEC will maintain ongoing monitoring of potential Alaska Highway pipeline developments and factors that may impact electrical loads in Yukon (including potential for electrical compression).
- **Southern Lakes hydrology assessments:** Continued assessment and studies of the hydrology of the southern lakes area, including identification of potential for water control structures to enhance output of Whitehorse Rapids, as well as potential hydro generation sites.
- **Other existing hydro facility enhancements:** Continued focus on projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases, Mayo. This includes full Level 3 and 4 studies on the Aishihik 3rd turbine and updating Level 2 studies on Aishihik diversions. Where suitable, activities should be carried out in conjunction with other normal Supply Side Enhancement planning by Yukon Energy, such as re-runnering.
- **Level 1 and 2 assessments to identify preferred 5-30 MW scale Yukon hydro sites**: There is an option to invest in further surveying the potential of other Yukon based hydro generation sites to try to identify good sites in the 5-10 MW range (within about 50 km of existing high voltage transmission) and to advance credible candidates in the 5-30 MW range through Level 2 assessments (including ongoing monitoring of hydrology) in order to identify more clearly preferred sites to develop for possible loads within this range. However, this activity is costly and may require assessment of a number of sites. No activities in this regard are recommended today; however, in the event that at least one large industrial load (such as Red Mountain or Division Mountain) proceeds to advanced licencing and likely commitment stages, it is proposed that this initial work should proceed quickly to determine if the sites identified to date are indeed the best candidates or if there are other Yukon-based sites that should be seriously considered, and to identify specific projects for Level 3 feasibility assessments.
- **Ongoing monitoring of hydrology**: Active hydrology monitoring will proceed where feasible for all hydro sites likely to be serious candidates for future development within the 20 year planning period. The monitoring may be periodic (seasonal flow information, current cost of $1,000 per year per site) up to a full-time recording station (at a current cost of $30,000 (initial costs) plus ongoing costs of between $10,000 to $15,000 per year).

TABLE OF CONTENTS

CHAPTER 1 - INTRODUCTION

1.0 INTRODUCTION 1-1
1.1 PURPOSE OF THE SUBMISSION 1-1
1.2 SCOPE OF SUBMISSION 1-2
1.3 RESOURCE PLANNING FRAMEWORK 1-3
1.3.1 Power Capacity and Energy in Yukon 1-4
1.3.2 Basic Planning Process 1-6
1.3.3 Resource Plan and Specific Capital Project Decisions 1-8
1.4 CURRENT YUKON SITUATION COMPARED WITH 1992 1-9
1.5 SUBMISSION OVERVIEW 1-13

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

2.0 BACKGROUND ON YUKON POWER SYSTEMS 2-1
2.1 OVERVIEW OF GENERATION FACILITIES AND TRANSMISSION IN YUKON 2-1
2.1.1 Generation in Yukon 2-3
2.1.2 Transmission in Yukon 2-7
2.2 OUTCOMES FROM THE 1992 REVIEW 2-8
2.3 MAJOR EVENTS AFFECTING POWER SYSTEMS SINCE 1992 2-13
2.3.1 Closure of the Faro Mine 2-13
2.3.2 The Growth of Secondary Sales 2-14
2.3.3 Shift to Direct Management 2-14
2.3.4 Whitehorse Rapids Generating Station Fire Rebuilding Project 2-15
2.3.5 Renewal of Water Licences at Whitehorse, Mayo and Aishihik 2-15
2.3.6 Mayo-Dawson Transmission Line 2-16
2.3.7 System Upgrades and Changes 2-17
2.4 BULK ELECTRICAL SUPPLY PLANNING SINCE 1992 2-17
2.4.1 Ongoing Yukon Energy Infrastructure Planning Process 2-18
2.4.2 BC Hydro Inventory of Potential Future Hydro Supply Options 2-18
2.4.3 Bulk Electrical Supply Infrastructure Condition Assessment Work 2-18
2.4.4 Generation Capacity Planning Criteria Review 2-18
2.4.5 Demand Side Management and the Energy Solutions Centre 2-19

CHAPTER 3 – SYSTEM CAPABILITY

3.0 SYSTEM CAPABILITY 3-1
3.1 CURRENT FACILITIES CONDITION ASSESSMENT 3-1
3.1.1 Yukon Energy's Response to Condition Assessments 3-2
3.1.2 Condition Assessment Findings Relevant to Resource Planning 3-5

3.2 CAPACITY AND ENERGY OUTPUT OF EXISTING FACILITIES 3-6
3.2.1 Whitehorse Rapids Hydro Firm Capacity.. 3-7
3.2.2 Aishihik Hydro Capacity and Energy... 3-9
3.2.3 Mayo Hydro Capacity 3-10
3.2.4 Whitehorse Diesel Capacity.. 3-10
3.2.5 Fish Lake Hydro (YECL) Capacity.. 3-11
3.3 CAPACITY PLANNING CRITERIA REVIEW 3-11
3.3.1 Background and Overview on the Evolution of Capacity Planning 3-12
3.3.2 Yukon Energy's Previous Capacity Planning Criteria (prior to late 2005) 3-14
3.3.3 Previous Yukon Criteria Compared with Criteria for Other Jurisdictions 3-17
3.3.4 New Criteria Adopted by Yukon Energy... 3-20
3.3.5 Rationale for Adopting a Two-Part Criteria on WAF and MD........................... 3-21
3.3.6 Implications of the Adopted Criteria 3-23
3.4 SUMMARY: REVISED CAPACITY PLANNING CRITERIA 3-25

CHAPTER 4 – NEAR TERM REQUIREMENTS

4.0 NEAR TERM REQUIREMENTS 4-1
4.1 PLANNING APPROACH AND TIMELINE 4-1
4.2 REQUIREMENTS.. 4-3
4.2.1 Basis for Non-Industrial Load Forecasts 4-4
4.2.2 Basis for Near Term Industrial Load Forecasts... 4-7
4.2.3 Near Term WAF Load –
Cases Analyzed Based on Non-Industrial and Industrial Requirements............... 4-7
4.2.4 Base Case Requirements 4-8
4.2.5 Low Sensitivity Case 4-10
4.2.6 Base Case with Mine Loads... 4-12
4.2.7 High Sensitivity Case Including Mines 4-14
4.3 OPTIONS... 4-16
4.3.1 Overview of "Opportunity" Project Options.. 4-17
4.3.2 Aishihik 3rd Turbine.. 4-19
4.3.3 Marsh Lake Fall/Winter Storage 4-20
4.3.4 Carmacks to Stewart Transmission Line Project 4-22
4.3.5 Overview of Major Capacity-Related Project Options 4-26
4.3.6 Mirrlees Life Extension Project 4-28
4.3.7 Whitehorse Diesel Replacement/Expansion Project 4-32
4.3.8 Aishihik 2nd Transmission Line Project 4-34
4.3.9 Supplemental Project Options 4-38
4.4 ASSESSMENT.. 4-39
4.4.1 Assessment of Opportunity Projects 4-40
4.4.2 Assessment of Capacity-Related Projects 4-46

4.4.3 Schedule and Sequencing of Alternatives 4-53
4.4.4 Rate related Impacts of Near Term Options 4-53
4.5 PROPOSED ACTIONS 4-57

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

5.0 INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES 5-1
5.1 PLANNING APPROACH AND TIMELINE 5-1
5.1.1 Need to Consider and Balance Several Key Factors 5-3
5.1.2 Regulatory and Policy Framework 5-7
5.1.3 Planning Framework 5-9
5.2 REQUIREMENTS 5-12
5.2.1 Scenario 1: A 10 MW WAF Industrial Scenario 5-18
5.2.2 Scenario 2: A 25 MW WAF Industrial Scenario 5-22
5.2.3 Scenario 3: A 40 MW WAF Industrial Scenario 5-24
5.2.4 Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline 5-26
5.3 OPTIONS 5-27
5.3.1 Overview of Resource Supply Options 5-28
5.3.2 Options for Scenario 1: A 10 MW WAF Industrial Scenario 5-38
5.3.3 Options for Scenario 2: A 25 MW WAF Industrial Scenario 5-38
5.3.4 Options for Scenario 3: A 40 MW WAF Industrial Scenario 5-40
5.3.5 Options for Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario 5-42
5.4 PRE-ASSESSMENT AND SCREENING 5-43
5.4.1 Technical Pre-Assessment and Load Fit 5-45
5.4.2 Economic Pre-Assessment 5-49
5.5 PROPOSED ACTIONS 5-51
5.5.1 Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario 5-52
5.5.2 Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario 5-53
5.5.3 Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario 5-54
5.5.4 Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario 5-55
5.5.5 Proposed "Pre-commitment" activities 5-56

APPENDICES

APPENDIX A: POWER RESOURCE TECHNOLOGY OPTIONS

A.1 POWER RESOURCE TECHNOLOGY OPTIONS A-1
A.1.1 DIESEL A-1
A.1.2 HYDRO A-2
A.1.3 WIND A-2

A.1.4 BIOMASS A-4
A.1.5 COAL A-5
A.1.6 COAL-BED METHANE A-6
A.1.7 NATURAL GAS A-6
A.1.8 GEOTHERMAL A-7
A.1.9 HYDROGEN A-7
A.1.10 SOLAR A-8
A.1.11 NUCLEAR A-8
A.1.12 DEMAND SIDE MANAGEMENT A-9
A.2 LITERATURE REVIEWED A-10
A.2.1 HYDRO A-10
A.2.2 WIND A-10
A.2.3 BIOMASS A-11
A.2.4 COAL A-11
A.2.5 LITERATURE REVIEWED ASSESSING MULTIPLE GENERATION TECHNOLOGIES A-11

APPENDIX B: HYDRO PROJECT OPTIONS

B.1 HYDRO PROJECT OPTIONS B-1
B.1.1 LEVELIZED COST OF ENERGY (LCOE) B-4
B.2 EXISTING HYDRO ENHANCEMENTS B-5
B.2.1 AISHIHIK DIVERSIONS B-5
B.2.2 ATLIN STORAGE B-5
B.3 VERY SMALL PROJECTS (1-4 MW) B-6
B.3.1 DRURY B-6
B.3.2 SQUANGA B-6
B.3.3 MORLEY, LAPIE AND ORCHAY B-7
B.4 SMALL PROJECTS (5-10 MW) B-7
B.4.1 MOON HYDRO SITE B-8
B.4.2 SURPRISE LAKE HYDRO SITE B-9
B.4.3 TUTSHI AND OTHER HYDRO SITES IN THE SOUTHERN LAKES B-10
B.4.4 MAYO B B-10
B.4.5 LACK OF OTHER YUKON-BASED HYDRO PROJECTS B-11
B.5 MEDIUM PROJECTS (10-30 MW) B-11
B.5.1 PRIMROSE/KUSAWA/TAKHINI HYDRO SITE B-11
B.5.2 FINLAYSON HYDRO SITE B-13
B.6 LARGE PROJECTS (30-60 MW) B-14
B.6.1 HOOLE B-14
B.6.2 SLATE B-14
B.6.3 HESS B-14

B.7 VERY LARGE PROJECTS (60 MW+) B-14
B.7.1 GRANITE CANYON B-14
B.7.2 FRASER FALLS B-15
B.7.3 VARIOUS OTHER LARGE YUKON RIVER SITES B-15

APPENDIX C: AISHIHIK 3RD TURBINE ASSESSMENT

C.1 AISHIHIK 3RD TURBINE ASSESSMENT C-1
C.2 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE LOAD C-4
C.3 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE WITH 10 MW MINE LOADS C-6
C.4 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS C-8
C.5 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE WITH 10 MW MINE LOADS C-10
C.6 AISHIHIK 3RD TURBINE AT 2011 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS C-12
C.7 SECTION C-7: AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE AND (2008) OF CARMACKS-STEWART (CS) UNDER BASE CASE WITH 10 MW MINE LOADS C-14

GLOSSARY OF TERMS

LIST OF TABLES

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

Table 2.1: Generation Capacity in Yukon – YEC and YECL in 2005 2-4

CHAPTER 3 – SYSTEM CAPABILITY

Table 3.1: BC Hydro Generation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s) 3-4
Table 3.2: BC Hydro Substation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s) 3-5
Table 3.3: Yukon Energy Generation Inventory 3-7
Table 3.4: Current WAF Generating Complement and Maximum Allowable Peak Load (MAPL) under Previous Planning Criteria 3-17
Table 3.5: WAF Peak and Capacity Surplus (Shortfall) as Whitehorse Diesels are Retired (MW).... 3-24

CHAPTER 4 – NEAR TERM REQUIREMENTS

Table 4.1: Near Term Non-Industrial Load Forecasts 4-5
Table 4.2: Summary of Near Term Opportunity Projects to 2012 (2005$ millions) 4-41
Table 4.3: Comparison of Near Term Capacity-focused Options to 2012 4-47

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Table 5.1 Industrial Development Opportunities 5-14
Table 5.2 Potential Hydro Resource Options 5-30

APPENDIX B: HYDRO PROJECT OPTIONS

Table B-1: Potential Hydro Sites B-2

APPENDIX C: AISHIHIK 3RD TURBINE ASSESSMENT

Table C-1: Summary of Aishihik 3rd Turbine Assessment Cases (2005$, $000s) C-3
Table C-2A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) – IRR based on cash flows C-4
Table C-2B: Aishihik 3rd Turbine Economics (65 years) – NPV based on annual impacts on ratepayers C-5
Table C-3A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) – IRR based on cash flows C-6
Table C-3B: Aishihik 3rd Turbine Economics (65 years) – NPV based on annual impacts on ratepayers C-7
Table C-4A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage IRR based on cash flows C-8

Table C-4B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers C-9
Table C-5A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage IRR based on cash flows C-10
Table C-5B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers C-11
Table C-6A: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Fall/Winter Storage – IRR based on cash flows C-12
Table C-6B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers C-13
Table C-7A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & Carmacks-Stewart (CS) S- IRR based on cash flows C-14
Table C-7B: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & (CS) S- NPV impacts on ratepayers C-15

LIST OF FIGURES

CHAPTER 1 – INTRODUCTION

Figure 1.1: 20-Year Resource Plan and Decisions on Specific Projects 1-9
Figure 1.2: Load Situation, Resource Needs and Supply Options 2006-2025................................. 1-12
Figure 1.3: Submission Overview 1-13

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

Figure 2.1 Map of Yukon Territory Power Infrastructure 2-2
Figure 2.2 Yukon Total Power Generation 1967-1997 2-5
Figure 2.3 YEC WAF Generation 1976-2004 2-6
Figure 2.4 Generation on MD 1980–2004 2-7

CHAPTER 3 – SYSTEM CAPABILITY

Figure 3.1: WAF System – Comparison of Capacity Criteria 3-25

CHAPTER 4 – NEAR TERM REQUIREMENTS

Figure 4.1: WAF Base Case Capacity Requirements 4-9
Figure 4.2: WAF Base Case System Energy Requirements.. 4-10
Figure 4.3: WAF Low Sensitivity Case Capacity Requirements 4-11
Figure 4.4: WAF Low Sensitivity Energy Requirements... 4-11
Figure 4.5: WAF Base Case with Mine Capacity Requirements 4-12
Figure 4.6: WAF Base Case with Mine Energy Requirements 4-13
Figure 4.7: WAF High Sensitivity Case with Mines Capacity Requirements 4-14
Figure 4.8: WAF High Sensitivity Case with Mines Energy Requirements 4-15
Figure 4.9: Carmacks to Stewart Transmission Line in 2008 4-25
Figure 4.10: Carmacks to Stewart Transmission Line in 2008 4-26
Figure 4.11: Mirrlees Life Extension 4-31
Figure 4.12: Whitehorse Diesel Replacement and Expansion 4-33
Figure 4.13: Aishihik Second Transmission Line 2009 4-36
Figure 4.14: Aishihik Second Transmission Line in 2009 (with Aishihik 3rd Turbine in 2009) 4-37
Figure 4.15: Timing and Sequencing of Opportunity and Capacity-Related Projects......................... 4-54

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Figure 5.1: Map of Industrial Development Opportunities and Power Infrastructure 5-13
Figure 5.2: Earliest In-Service Dates and Power Loads for Potential Mine Developments................ 5-16
Figure 5.3: Scenario 1: WAF Capacity Requirements 5-20
Figure 5.4: Scenario 1: WAF Energy Requirements.. 5-21
Figure 5.5: Scenario 2: WAF Capacity Requirements 5-23
Figure 5.6: Scenario 2: WAF Energy Requirements.. 5-24

Figure 5.7: Scenario 3: WAF Capacity Requirements 5-25
Figure 5.8: Scenario 3: WAF Energy Requirements........ 5-26
Figure 5.9: Map of Potential Supply Option Sites........ 5-29

APPENDIX B: HYDRO PROJECT OPTIONS

Figure B-1: Map of Potential Supply Options B-3
Figure B-2: WAF Energy Requirements under 25 MW Scenario with Moon Lake Hydro........ B-9
Figure B-3: WAF Energy Requirements under 40 MW Scenario with Primrose Hydro........ B-12
Figure B-4: WAF Energy Requirements under 25 MW Scenario with Primrose Hydro........ B-13

1.0 INTRODUCTION

Yukon Energy Corporation's ("YEC" or "Yukon Energy") 20-Year Resource Plan Submission addresses major generation and transmission requirements in Yukon during the period 2006 to 2025. The last Resource Plan, which was submitted for review by the Yukon Utilities Board ("YUB") in 1992, covered 1992-2001 and was prepared by YEC and Yukon Electrical Company Limited ("YECL").

This chapter sets out the purpose, scope, framework, and approach and outline of the 20-Year Resource Plan Submission. The sections for this chapter are as follows:

- Section 1.1: Purpose of the Submission
- Section 1.2: Scope of the Submission
- Section 1.3: Resource Planning Framework
- Section 1.4: Current Yukon Situation Compared with 1992
- Section 1.5: Submission Overview

1.1 PURPOSE OF THE SUBMISSION

The Resource Plan Submission provides Yukon Energy's 20-Year Resource Plan with respect to major electrical generation and transmission requirements during the 2006 to 2025 period, with emphasis on:

a) near term projects that will require YEC commitments before the year 2009 with costs of $3 million or more, and
b) planning activities that YEC may be required to carry out in order to start construction on other projects before 2016 to meet the needs of potential major industrial customers or other major potential developments in Yukon.

Yukon Energy is committed to seek YUB review, prior to construction, of any new capital project costing $3 million or more. Yukon Energy's December 2004 Application to the YUB regarding 2005 Required Revenues and Related Matters also committed Yukon Energy to bring forward to the YUB new or revised capacity planning criteria in advance of capital investment in new generation for capacity reasons. Accordingly, the 20-Year Resource Plan Submission is expected to provide the YUB with the opportunity to review near term generation or transmission projects costing $3 million or more, including projects that are required based on revised capacity planning criteria now adopted by Yukon Energy.

The Submission also proposes Yukon Energy planning activities within the next 10 years to protect YEC's ability to start construction on other major generation and transmission projects before 2016 to meet the needs of potential major industrial development opportunities. In some circumstances, to identify and protect power resource options related to industrial development opportunities, some of these planning commitments will need to be made on some form of contingent basis in advance of resolving various major uncertainties.

1.2 SCOPE OF SUBMISSION

The planning and development of new transmission and generation projects requires a forward looking perspective regarding major objectives, options, policies and planning activities. The Resource Plan Submission identifies generation and transmission issues and options facing Yukon Energy in both the near term (i.e., prior to 2009), and within the next 10 to 20 years. The Submission also provides an overview of the development and composition of Yukon's power systems; an update on Yukon Energy's capital planning process since the last Resource Plan submitted in 1992; and the context today for bulk electrical supply ("BES") planning by Yukon Energy.

With regard to near term generation and transmission projects of $3 million or more included in the Plan for construction start within the next three years (i.e., by 2009), Yukon Energy has examined:

- the necessity of the proposed spending commitments, their expected effects on overall utility costs and electricity rates, and (to the extent currently known) their physical and engineering characteristics and their economic consequences;
- the capability and condition of existing generation and transmission facilities, taking into account appropriate capacity planning criteria;
- forecast load requirements for electricity and the need for spending commitments to meet these forecast requirements;
- all reasonable alternative near term options and developed proposals based on reasonable grounds; and
- the potential risks of each option.

During the planning process, Yukon Energy reviewed the studies and activities that have taken place before and after 1992. Major initiatives carried out in the past few years include a review the condition of existing assets, and an examination of the adequacy of the current capacity planning criteria. Additional technical project-specific feasibility or planning studies have generally not been carried out since 1992, beyond developments actually undertaken such as the Mayo Dawson Transmission Line Project. Yukon Energy also completed an initial review of a potential Carmacks-Stewart Transmission

Line in 2002; a review of a potential Atlin Transmission Line in 2003; and a Small Hydro Assessment in 2004.

Major near term projects addressed in the Submission for construction start prior to 2009 are the result of the adoption in late 2005 of revised capacity planning criteria. Studies are ongoing with regard to leading near term major project options. The Submission proceeds on the basis of current information regarding these near term options, setting out the conditions relevant to proceeding with any specific option. Updates will be provided during the review of the Submission to the extent that relevant new information is forthcoming from ongoing studies on these projects.

Longer term opportunities addressed in the Submission are contingent on the extent to which new industrial developments do in fact move forward during the next 10 to 20 years. The Submission identifies representative scenarios related to possible future industrial development, and the planning activities appropriate for Yukon Energy to identify and protect relevant generation and transmission options that may need to be developed with respect to these scenarios.

1.3 RESOURCE PLANNING FRAMEWORK

In Yukon, electric power resource planning focuses separately on each electric power system. The Whitehorse-Aishihik-Faro ("WAF") grid, and the Mayo-Dawson ("MD") grid are typically planned as separate systems, as are each of the isolated diesel-served communities.

The basic electric power resource planning model addresses separately each system's generation **capacity** (MW [megawatts], particularly at the time of system winter peak) and its **energy** generation kW.h or MW.h [kilowatt hours or megawatt hours] over the full year). An overview of power capacity and energy in Yukon is provided below (Section 1.3.1).
The basic resource planning process in the Submission is then reviewed (Section 1.3.2), including the following elements (in the following sequence) which the Submission examines separately as required for capacity and energy on both the WAF and MD systems:

1. **System Capability** – existing system capability over the next 20 years, based on the condition of existing facilities, firm capability of these facilities at the time of winter peak, and capacity planning criteria for each system that define generation capacity (MW) adequacy and load carrying capability;

2. **System Requirements** – capacity and energy requirements forecast over the next 20 years (and beyond) for each system in order to assess the loads that may need to be met under different industrial development scenarios;

3. **New Facility Requirements** – the capability of installed plant on each system over the next 20 years compared to forecast system requirements (to establish forecast requirements for new facilities under each load scenario);

4. **Options** – resource options to meet new facility requirements for each load scenario on each system;

5. **Assessment of Options** – resource options are assessed and/or screened, to the extent feasible today, based on consideration of technical feasibility (including timing), cost efficiency, reliability and risk.

1.3.1 Power Capacity and Energy in Yukon

As the main generator and transmitter of electrical power in the Yukon region, Yukon Energy focuses on serving and planning for the capacity and energy requirements of Yukoners, particularly those supplied on the WAF and MD grids. An overview of power capacity and energy in Yukon is provided below.

Capacity: The capacity requirement on a power system in any year is the highest or peak generation capability (MW) required during the year. This required capability reflects both the operating generation capability needed to serve the peak loads on the system (including provision for system losses over and above customer loads) plus the provision of sufficient generation reserve capability to address unplanned generation outages (based on the system's capacity planning criteria).
Capacity requirements on Yukon systems typically drive the need to develop a specific MW amount of new generation facilities within a certain time period. The type of generation selected, however, may depend on forecast energy requirements[1].

[1] Diesel generating units have low capital costs, and very high operating costs; accordingly, diesel units are typically well-suited to meeting capacity needs during system peaks and as reserve capacity, rather than being run to provide sustained energy on a regular basis throughout the year. Conversely, hydro generating plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units.

In Yukon, the peak power requirement is typically in the winter. For example, during the winter of 2004/05, the WAF system peak occurred on Wednesday January 12th, 2005, when the temperature reached -44.5 degrees Celsius. The WAF system integrated hourly peak for generation on that day was 56.4 MW.

The capacity capability of generation facilities can vary depending on the time of year. For example, the winter peak in Yukon occurs on the WAF grid when the capability of the Whitehorse Hydro Plant is reduced due to lower water flows. For a hydro asset, the amount of electricity that the asset can generate is determined in part by the volume of water moving through the plant. The amount of water flowing through the Whitehorse Plant in the winter months under normal or low flow water regimes is typically lower than in the summer months. Accordingly, given that there is very little reservoir storage to retain water for the winter, the Whitehorse Plant firm capacity in the four coldest winter months (about 24 MW) is well below its peak capacity in the summer months (40 MW).

The capacity planning criteria applied on each Yukon system in the past, as reviewed and recommended by the YUB in 1992, in effect provide a requirement for "reserve generation capacity" equal to the capacity needed to meet forecast winter peak load with the loss of the single largest winter generation unit (on WAF, this is one 15 MW hydro unit at Aishihik) plus the loss of 10% of the installed diesel capacity[2]. In light of changes since 1992, it became timely to review the adequacy of the current capacity planning criteria for the WAF and MD systems.

Energy: The annual energy requirement on a power system is the number of kilowatt hours of electricity that are required to be generated.

Generation requirements are higher than the sales to customers as a result of system losses between the generation plant and the customers as well as generation station service power requirements. Yukon Energy must generate enough electricity to serve its load, and to account for the associated line and other system losses. Between 2000 and 2004, Yukon Energy's energy losses overall required generation averaging 8% more than YEC's sales to its customers.

Yukon's existing diesel generation facilities on each system typically are sufficient to provide a reliable supply of firm energy to meet system loads, even under low flow conditions for the hydro generation

[2] On isolated systems, this is worded so as to require the diesel plant installed, less the largest unit, to be 110% of the forecast peak.

facilities. The prime energy-related issue when assessing new facilities in Yukon therefore relates to the opportunity to displace diesel generation with less costly energy supply alternatives.

Energy requirements in Yukon may establish the economic opportunity for certain types of new generation or even transmission facilities. If sufficient energy is required on a sustained basis, past Yukon experience has shown that opportunities may emerge to develop new hydro or transmission facilities (with access to surplus or cost competitive hydro generation) to displace what would otherwise be served by diesel generation. These opportunities arise because hydro plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units[3].

Current surplus hydro generation capability on both the WAF and MD systems limit opportunities today for developing new lower cost generation on these systems. The Resource Plan identifies the future growth conditions required before the current surplus hydro would be fully utilized and new opportunities may emerge to displace diesel generation on these systems.

1.3.2 Basic Planning Process

The basic planning process that Yukon Energy undertook to develop its 20 Year Resource Plan included the following elements:

1. **System Capability:** Existing system capability over the next 20 years was assessed, based on the condition of existing facilities, firm capability of these facilities at the time of winter peak, and capacity planning criteria for each system that define generation capacity (MW) adequacy and load carrying capability.
   a) **Condition assessments of existing facilities:** Yukon Energy commissioned assessments of its existing facilities to determine their condition and their remaining life. The prime focus for the Resource Plan from these assessments is the potential timing for retirement of any generation or transmission facilities during the next 20 years.

[3] Conversely, diesel units have low capital costs and very high operating costs; accordingly, diesel units are typically well-suited to meeting capacity needs during relatively brief system peak periods, rather than being run to provide sustained energy on a regular basis throughout the year. Diesel units, however, can be cost effective for sustained operation in many specific situations, e.g., Yukon experience demonstrates instances involving isolation from a grid and/or viable energy options, small scale of requirements, or short term time periods for requirements.

b) **Firm capability of existing facilities:** The ability of these facilities to provide capacity and energy was reviewed, particularly at system peak periods in winter. This included planned retirements and age-related derates.

c) **Capacity planning criteria review:** Capacity planning criteria were thoroughly reviewed for each system. These criteria establish the "reserve" capacity (MW) capability that must be planned over and above the capacity needed to supply forecast system winter peak load when each facility is operating at its respective capability (e.g., the reserve needed to cover reasonable contingencies regarding potential generation and transmission or BES unit failures). Yukon Energy has adopted revised capacity planning criteria as a result of this review.

2. **System Requirements Forecasts:** Capacity and energy requirements were forecast over the next 20 years (and beyond) for each system in order to assess the loads that may need to be met under different industrial development scenarios. For Yukon, a key historic driver has been opening and closing of major industrial loads (new or existing mines) and planning for each system must therefore address different industrial load scenarios. Generation and transmission are designed, built and operated on each system to provide reliable supply of both capacity and energy to meet forecast non-industrial and industrial requirements:

   a) **Capacity requirement forecasts:** These forecasts address the peak facility power requirements (MW) at the specific time of the system annual peak load in winter, including the provision of sufficient generation reserve capability to meet the capacity planning criteria.

   b) **Energy requirement forecasts:** These forecasts address the energy requirements (kW.h) over the full year; and, where relevant, seasonal energy requirements.

3. **Forecast New Facility Requirements:** The capability of installed plant on each system over the next 20 years was compared to forecast system requirements (to establish forecast requirements for new facilities under each load scenario):

   a) **New capacity requirements:** New capacity requirements reflect the extent to which forecast MW requirements at the time of system peak in winter (including provision to meet capacity planning criteria for reserve capability) exceed the forecast system capability of existing plant (i.e., reliable MW of capacity from what is installed today, less those units that are retired over time). Given the short duration of peak capacity needs in any year, capital cost minimization will typically be a key factor in selecting new facility options required solely to meet new capacity needs.

b) **New energy opportunities:** To the extent that such requirements affect the choice for new facilities, new energy requirements in Yukon typically reflect cost effective opportunities to displace either existing or new diesel fuel energy generation.

4. **Resource Options:** Supply side options to meet new capacity and/or energy requirements on each system include: enhancing existing generation facilities; extending the life of existing generation facilities; developing new generation plants (diesel, hydro, coal, wind, biomass, etc); and/or developing new transmission facilities connecting existing and/or new resources to load centres. Demand side options also exist, including conservation, load management, and customer efficiency improvements.

5. **Assessment of Resource Options:** Available options to meet new capacity and/or energy requirements on each system are assessed and/or screened based on consideration of technical feasibility (including timing), cost efficiency, reliability, and risk.

1.3.3 Resource Plan and Specific Capital Project Decisions

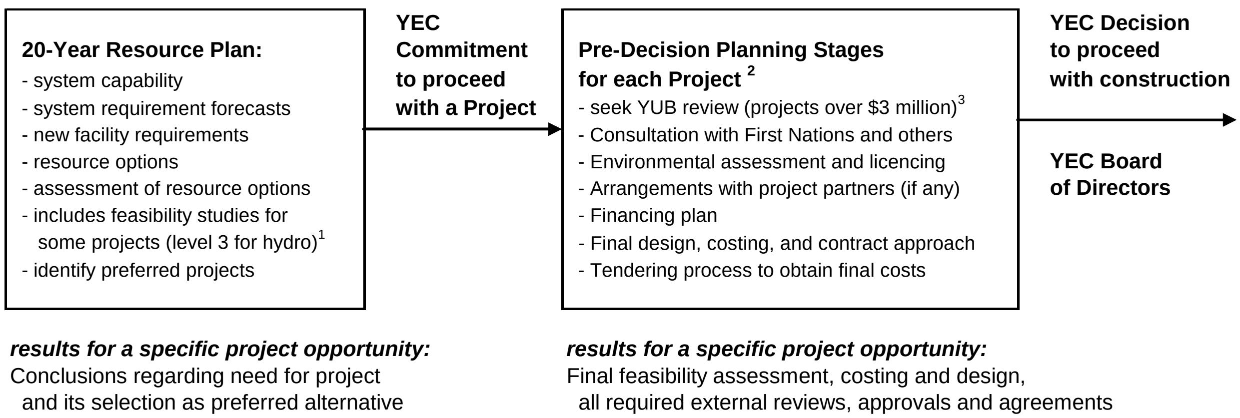
Figure 1.1: 20-Year Resource Plan and Decisions on Specific Projects reviews the relationship between the 20-Year Resource Plan process and activities leading to final Yukon Energy construction decisions on specific project opportunities identified by the Resource Plan.

The structure and framework of the 20-Year Resource Plan reflect overall broad capabilities and requirements for each system, options to fulfill requirements and/or capture opportunities identified for new facilities, and comparisons/assessments between the options. In assessing specific resource options under the Resource Plan, Yukon Energy carries out varying levels of technical and costing assessments to enable screening of options, including in some instances investigations advanced to the project feasibility stage. The Resource Plan process in this manner identifies preferred projects for which YEC can then commit to proceed with more detailed project-specific pre-decision planning.

Figure 1.1 identifies pre-decision planning stages that Yukon Energy carries out, as needed, for each preferred project identified by the Resource Plan process prior to any final decision to proceed with construction or implementation. Pre-decision planning for each project reflects specific requirements for that project, including anticipated regulatory review and/or approval needs, consultation requirements, any arrangements needed with other parties, final design and costing needs, and timing needs for bringing the project into service.

This Submission includes near term projects at different stages of pre-decision planning. No final decision has yet been made to implement these projects. In some instances, environmental approvals have already been secured – in other instances; however, the necessary applications for such approvals have yet to be made. Final design, costing and tendering tend to be a final stage to be carried out prior to final Yukon Energy decisions to proceed with construction/implementation.

Figure 1.1:
20-Year Resource Plan and Decisions on Specific Projects



1 - In large projects (e.g., over $30 million), project feasibility stages can exceed $3 million and YEC would then seek YUB review prior to commitment to these stages.
2 - For individual projects, these planning stages will proceed in different sequences and with different timing. For projects over $3 million,Yukon Energy is committed to seek YUB review prior to a decision by the YEC Board to proceed with construction.
3 - An OIC under the Yukon Utilities Act can direct the YUB to review a YEC submission on need and justification for a project and to report on its findings to the Commissioner in Executive Council. This type of YUB review would be separate and distinct from a normal YUB review of project rate base costs as required for a Yukon Energy revenue requirements and rate application.

1.4 CURRENT YUKON SITUATION COMPARED WITH 1992

The last Resource Plan that was submitted to the YUB in 1992 was filed jointly by Yukon Energy and Yukon Electrical Company Limited, and reflected a situation very different from that facing the Yukon today. At that time, the Faro mine was in operation, the WAF system was consuming significant diesel fuel throughout each year, and there were substantial uncertainties regarding the life of the Faro mine load (about 25 MW and up to 180 GWh/yr). The submission also covered the potential opening of new mines; extensive planning studies previously carried out on Demand Side Management ("DSM"); various hydro supply development options; and possible transmission developments. There were no projects being requested in the near term, and the applicability of nearly all projects hinged on which mine load "scenario" was going to arise, and the risks associated with the load. In the end, due to substantial downside risk related to existing loads, the 1992 Resource Plan did not propose any near or long term projects for development.

The Yukon economy, and Yukon's electricity loads and systems have changed substantially since the 1992 review. Due to the closure of the Faro mine, no reopening of the United Keno Hill Mine ("UKHM"), and no new mines yet having emerged, there is currently a surplus of hydro energy available on the WAF and MD grids. Potential new industrial developments during the next several years may absorb the WAF hydro energy surplus. However, forecast load growth even without new industrial loads, pending retirement of existing diesel generation and the adoption of new capacity planning criteria indicate an immediate need in any event to provide new WAF generation capacity to serve winter peak load requirements even through the WAF hydro energy surplus could remain for most of the current 20 year planning period.

Beyond near term needs and opportunities, current planning issues must be addressed regarding other potential future major industrial loads and developments during the next 10 to 20 years, including the Alaska Highway Natural Gas Pipeline project. Potential industrial loads need to be considered, and the identification, definition and "protection" of appropriate resource options is required to ensure that Yukon Energy is able to meet new loads when relevant on a timely basis if and when they develop.

Supply side options potentially relevant for a construction start within the next 10 years vary widely depending on the potential industrial developments considered, and include a range of different hydro possibilities as well as coal-fired generation and potentially natural gas-fired generation.

Lead times required to plan, approve and develop major new power supply projects, as well as the material planning costs associated with pre-construction activities required to keep these options available on a timely basis, underline the relevance of the current Resource Plan review.

Yukon Energy has organized generation and transmission project options by different load situations and resource needs. As shown in *Figure 1.2 Load Situation, Resource Needs and Project Options*, the resource needs (capacity or energy) are the primary driver in evaluating the appropriateness of an option for a given scenario. New industrial loads of less than 10 MW typically give rise to capacity-focused options, while new industrial loads above 10 MW may create opportunities for energy-focused options, driven in part by specific opportunities to enhance existing hydro systems and in part by Yukon Energy's revised capacity planning criteria. Changes in Yukon power systems, significant load growth in the Whitehorse area and the potential retirement of three diesel units at Whitehorse prompted a re-examination of these planning criteria. Yukon Energy believes that its revised criteria better reflect the Yukon electrical grids' reliability requirements today.

- **Potential near term major project options** include opportunities, projects and major capacity shortfall projects as noted in Figure 1.1. These near term project opportunities and options are examined in the context of a range of possible load situations (see Figure 1.2).
- **Opportunities projects** include enhancements to existing hydro facilities at Whitehorse and Aishihik as well as possible access to government infrastructure funding to develop a Transmission Line from Carmacks to Stewart Crossing connecting the WAF and MD systems.
- **Major capacity shortfall project options** address major new WAF system capacity needs in the context of current surplus hydro energy on both the WAF and MD systems.

As outlined in Figure 1.2, planning activities to proceed with other generation or transmission projects beyond 2009 and before 2016 are being driven by the potential needs of a diverse range of possible major industrial customers (such as various possible major new mines) or other major potential industrial developments (i.e., Alaska Highway Pipeline project), and the energy requirements and/or opportunities related to such industrial developments. The Submission examines these opportunities in the context of the different possible load situations outlined in Figure 1.2, the significant uncertainties associated with such load possibilities, and the lead times and other needs associated with Yukon Energy protecting appropriate resource options related to these different loads.

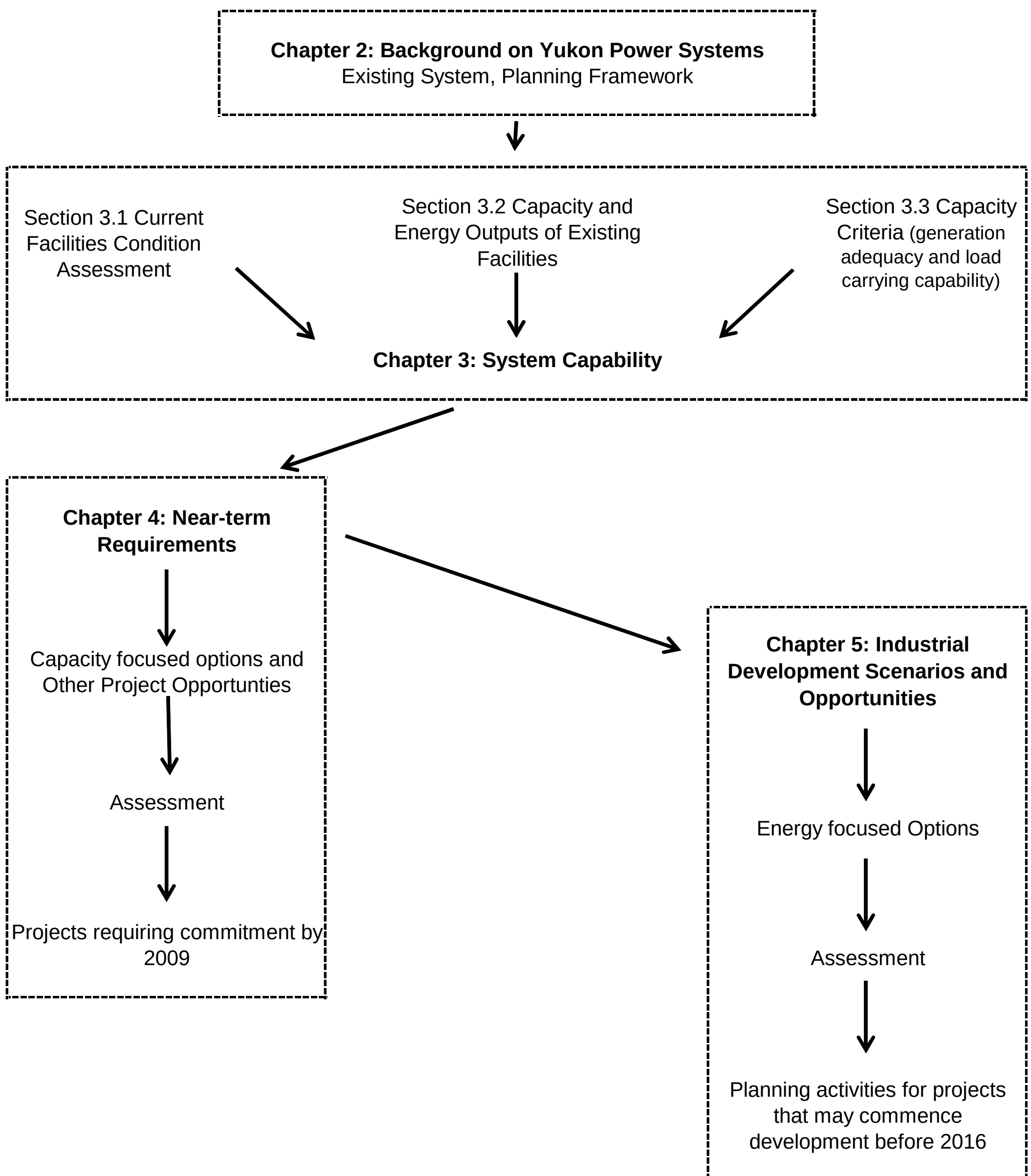
Figure 1.2:
Load Situation, Resource Needs and Supply Options 2006-2025

Load Situation (WAF Scenarios)	Resource Needs	Well Defined Project Options	Relatively Undefined Project Options
Scenario 4: **A 120 to 360 MW Alaska Highway Natural Gas Pipeline Scenario**	Large Energy (223 to 894 GW.h/yr, starting at earliest in 2012-2015 time period)		• Granite (80 MW, 660 GW.h/yr up to perhaps 254 MW) • Hoole (40 MW, 275 GW.h/yr) • Fraser Falls (100 MW, 613 GW.h/yr up to perhaps 450 MW) • Yukon River (multiple sites including Rink Rapid, Eagles Nest and Five Fingers, 75-240 MW) • Two Mile Canyon on Hess (53 MW, 280 GW.h/yr), Slate (42 MW, 266 GW.h/yr) • Natural Gas (to be determined)
Scenario 3: **A 40 MW WAF Industrial Scenario: Substantial Mining Industry Development in Excess of the Faro Mine** (more intense mine development than Scenario 2)	More Energy (max about 250 to 300 GW.h/yr during life of mine projects) Following mine closures, energy requirements at 56 GW.h or less		• Primrose (28 MW, 141 GW.h/yr) • Finlayson (17 MW, 129 GW.h/yr) • Coal (previously studied at 20 MW, about 144 GW.h/yr, up to 50 MW or larger, no credible smaller concept developed to date)
Scenario 2: **A 25 MW WAF Industrial Scenario: Multiple Major Developments Comparable to Faro Mine** (similar to Faro Mine, could comprise multiple mines, such as Minto, Carmacks Copper plus Red Mountain or Division Mountain coal)	Smaller Energy (max about 100 GW.h/yr for life of mine projects) Following mine closures, energy requirements at 35 GW.h or less	• Drury (2.6 MW up to perhaps 5.2 MW, 23 GW.h/yr)	• Moon (8.5 MW, 50 GW.h/yr) • Mayo B (10 MW, 48 GW.h/yr) • Aishihik Diversions (maximum 24 GW.h) • Tutshi (7.5 MW, 51 GW.h) • various other hydro (Orchay, Morley, Lapie,Squanga) • Surprise (8.5 MW, 50 GW.h/yr; removed by other proposals)
Scenario 1: **A 10 MW WAF Industrial Scenario: Combined Industrial load up to about 10 MW** (focus on Minto and Carmacks Copper mines [9-11 MW, about 60 GW.h/yr], 8-12 years)	Capacity focus - absorb current WAF surplus hydro while both mines operate (21 to 27 MW shortfall by 2012, base case and high load sensitivity)	Minor added capacity over and above base case (diesel or other options noted below)	
Base Case: **Existing Non-Industrial Loads** (new capacity planning critieria, retirement of 11.4 MW of Whitehorse diesel capability (3 Mirlees units))	Capacity shortfall focus - WAF surplus hydro likely until near end of 20 (Base Case shortfall by 2012 at 19 MW; range 15 to 24 MW)	**Major Capacity Shortfall Projects** • WH Diesel Replacement/Expansion Project (15-24 MW by 2012 wihout new industrial loads) • Mirrlees Life Extension Project (14 MW) • Aishihik 2nd Trans. Line (up to 22 MW, 0 GW.h/yr) **Opportunity Projects** • Aishihik 3rd Turbine (7 MW, 5.4 GW.h/yr) • Marsh Lake Fall/Winter Storage (1.6 MW, 7.7 GW.h/yr) • WAF-MD Interconnect (about 6 MW, 15 GW.h/yr, decreasing as MD load grows)	• Atlin Lake Top Storage (2.0 MW, 9 GW.h/yr) • Aishihik Supply Side Enhancements (about 6 MW potential) • Other Southern Lakes (to be determined)

1.5 SUBMISSION OVERVIEW

Figure 1.3: Submission Overview provides an overview of the organization and the interconnections that are present in the document.

**Figure 1.3:
Submission Overview**



The document is composed of five chapters:

Chapter One: Introduction provides the framework for the Submission.

Chapter Two: Background on Yukon Power Systems provides background information. The chapter includes an overview of the Yukon power system; the outcomes from the 1992 review; major events affecting power systems since 1992; and bulk power planning since 1992.

Chapter Three: System Capability provides information on the capability of the Yukon systems to meet the electricity needs of Yukoners, and addresses a review of system capacity planning criteria and the revised criteria that Yukon Energy has adopted.

> **Figure 1.3:** Depicts the three sections of Chapter Three. These sections are separate, but each contributes in determining the adequacy of the system.
>
> **Section 3.1:** Current Facilities Condition Assessment provides information on Yukon Energy's generation, substation and transmission assets. The second section of the chapter,
>
> **Section 3.2:** Capacity and Energy Outputs of Existing Facilities focuses on implications of changes to major facility output since 1992, either from age, enhancement, or licencing conditions. The third section of the chapter,
>
> **Section 3.3**: Capacity Planning Criteria Review, provides information on Yukon Energy's previous capacity criteria, the Company's 2005 review of its capacity criteria, and its adoption of revised criteria.

The next two chapters of the Plan reflect differentiation of (a) the near term requirements, and (b) longer term industrial development scenarios and opportunities.

Chapter Four: Near Term Requirements reviews major projects currently in the pre-decision planning stage (Figure 1.1) that Yukon Energy proposes to commit for construction or implementation prior to 2009, focusing on near term opportunities with regard to enhancing existing Yukon Energy facilities as well as near term projects which Yukon Energy is required to address under the revised capacity planning criteria. Proposed actions by Yukon Energy are identified regarding major projects that require final commitment decisions prior to 2009.

Chapter Five: Industrial Development Scenarios and Opportunities identifies and assesses on a preliminary basis major energy focused project possibilities during the 20 year planning period beyond 2009 and before 2016 in response to different industrial development scenarios. Proposed actions by

Yukon Energy are identified regarding planning activities that Yukon Energy may be required to carry out to start construction on such projects before 2016, including actions to ensure that YEC protects its ability to deal with these industrial development loads and opportunities should they arise. No project options examined in Chapter 5 are yet at the pre-decision stage of project planning (as reviewed in Figure 1.1).

2.0 BACKGROUND ON YUKON POWER SYSTEMS

The chapter provides background on current Yukon power systems, primarily encompassing the two integrated grids and generation facilities and transmission owned by Yukon Energy.

The sections for this chapter are as follows:

- Section 2.1: Overview of Generation Facilities and Transmission
- Section 2.2: Outcomes from the 1992 Review
- Section 2.3: Major Events Affecting Power Systems Since 1992
- Section 2.4: Bulk Electrical Supply Planning Since 1992

2.1 OVERVIEW OF GENERATION FACILITIES AND TRANSMISSION IN YUKON

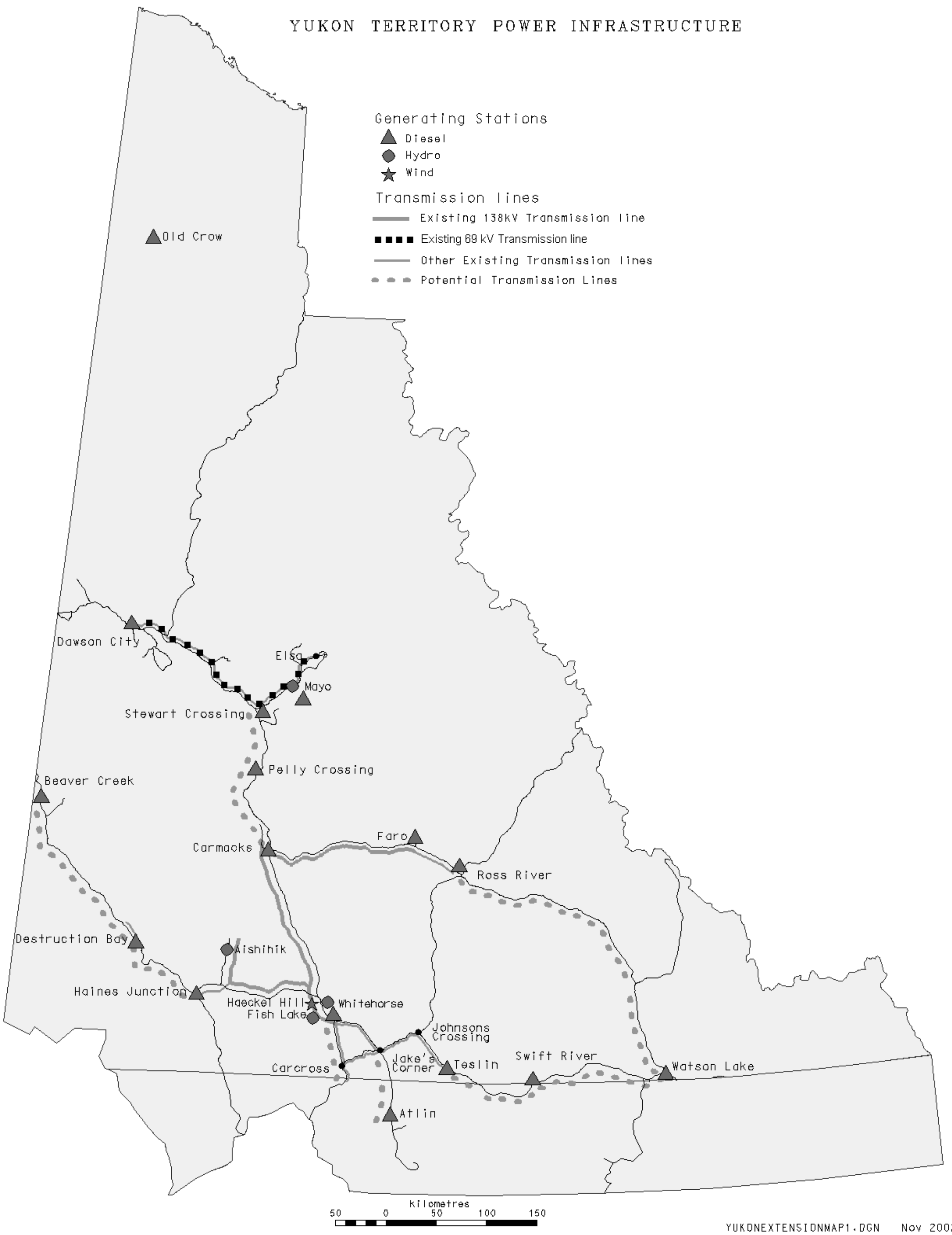
Yukon Energy is the main BES provider, or main generator and transmitter of electrical energy in Yukon. Yukon Energy currently accounts for 90% of annual Yukon power generation, and operates two independent transmission grids – the WAF and the MD.

The power systems identified in this Resource Plan are distinct and independent systems, each being served by its own source(s) of generation. The power systems in the Yukon include: the WAF grid; the MD grid; the diesel community of Watson Lake; and a number of smaller isolated diesel communities (Beaver Creek, Destruction Bay, Pelly Crossing, Swift River and Old Crow). The Yukon power systems are shown in *Figure 2.1: Map of Yukon Territory Power Infrastructure*.

Yukon Energy currently serves approximately 1700 retail customers, or 11%, of Yukon's customers directly. The retail customers that are served directly include residential and commercial classes. The majority of these customers are located in and around Dawson City, Mayo and Faro.

Yukon Energy's wholesale customer, YECL, distributes power to the other 89% of Yukon's retail customers. The bulk of Yukon Energy's sales are composed of firm wholesale sales to YECL on the WAF grid. YECL maintains and operates its distribution lines independent of Yukon Energy.

Figure 2.1:
Map of Yukon Territory Power Infrastructure



Hydro generation from the Aishihik and Whitehorse stations supply the WAF communities of: Carmacks, Carcross, Haines Junction, Teslin, Whitehorse, Ross River, Tagish, Deep Creek, Takhini River Sub and Marsh Lake through wholesale sales to YECL. The WAF communities of Champagne, Faro, Johnsons Crossing and Braeburn are served directly by Yukon Energy.

Hydro generation from the Mayo Generating station is supplied by Yukon Energy to the Town of Mayo, the City of Dawson, as well as to loads along the Mayo-Dawson transmission line route (the North Klondike Highway loads), as well as on a wholesale basis to YECL for service to Stewart Crossing, Elsa, and Keno.

Hydro generation stations on the Yukon grids are supplemented as necessary by a small amount of diesel for peaking or maintenance purposes, and on the WAF grid, by wind generation. The absence of power grid interconnections with other neighbouring jurisdictions prevents export of surplus generation or import of competitive supplies, and is one of the key factors distinguishing Yukon's situation from that prevailing in most southern jurisdictions in Canada.

2.1.1 Generation in Yukon

Yukon Energy's systems account for 112.4 MW of the 127.4 MW of installed capacity in Yukon. The YECL systems account for the balance, or for 15.0 MW of installed capacity.

The generation assets currently owned by both Yukon Energy and YECL are shown in *Table 2.1: Generation Capacity in Yukon – YEC and YECL in 2005*.

Table 2.1:
Generation Capacity in Yukon – YEC and YECL in 2005

Yukon Energy Generation Assets (in MW installed & currently rating)			**YECL Generation Assets** (in MW installed)		
Hydro Facilities			Hydro Facilities		
Whitehorse	WAF	40.0	Fish Lake	WAF	1.3
Aishihik	WAF	30.0	Base Load Diesel Facilities		
Mayo	MD	5.4	Old Crow	Isolated	0.7
Total Hydro		75.4	Pelly Crossing	Isolated	0.7
			Beaver Creek	Isolated	0.9
Wind Facilities			Destruction Bay	Isolated	0.9
Haeckel Hill	WAF	0.8	Swift River	Isolated	0.3
			Watson Lake	Watson Lake	5.0
Diesel Facilities			Back-up Diesel Facilities		
Whitehorse	WAF	22.4	Carmacks	WAF	1.3
Faro	WAF	5.3	Teslin	WAF	1.3
Dawson	MD	5.0	Haines Junction	WAF	1.3
Mayo	MD	2.0	Stewart Crossing	MD	0.3
Mobile Diesel		1.5	Ross River	WAF	1.0
Total Diesel		36.2	Total Diesel		13.7
TOTAL YUKON ENERGY		112.4	TOTAL YECL		15.0
TOTAL YUKON GENERATION		**127.4** (YEC + YECL)			

Yukon Energy's extensive hydro generation and transmission facilities and the resulting significant reduction in overall reliance on diesel generation are the key factor causing Yukon power costs to typically be lower than those found in Alaska or the Northwest Territories ("NWT"). Without such hydro facilities, Yukon utilities probably would have relied almost entirely on diesel generation with its associated higher costs[1].

[1] See Cabinet Commission on Energy, Technical Background Paper on Electrical Rates and Relief, 1997. Chart 1 in this paper reviewed Residential power bills in North America in 1996. The paper (pages 6-7) reviewed factors affecting northern power costs (e.g., lower population and customer densities, reliance on diesel generation, and the absence of power grid connections with other jurisdictions), and concluded that the lower power costs in Yukon reflect YEC's extensive hydro generating facilities (e.g., YEC hydro generation provided from 70 to 90% of all Yukon power generation each year from 1987 through to 1997). The paper noted that production or generation costs represented almost 70% of all Yukon power costs forecast for 1997 in the 1996/97 GRA.

Figure 2.2:
Yukon Total Power Generation 1967 – 1997

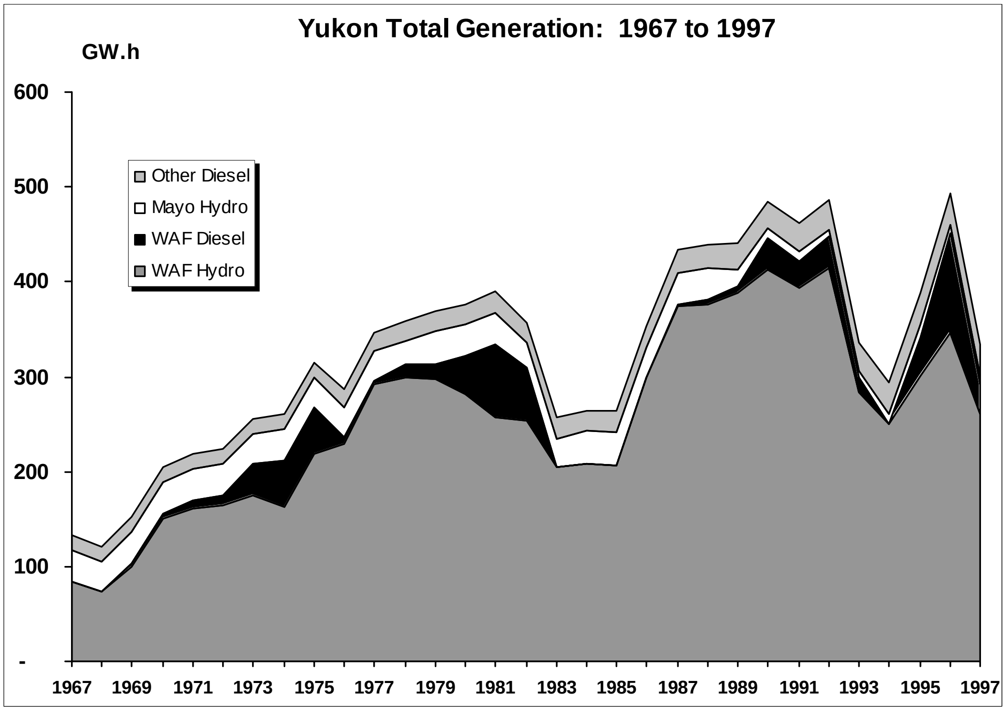


Figure 2.2: Yukon Total Power Generation: 1967-1997 highlights the overall importance of Northern Canada Power Commission ("NCPC")/YEC hydro generation in Yukon and the evolution of this capability from the late 1960's (after the first two hydro units were installed at Whitehorse Rapids) until the mid 1980s. This figure also demonstrates the relatively minor effect overall for Yukon related to diesel generation required outside the WAF and Mayo areas[2].

Hydro generation in Yukon was developed in the past by the NCPC in response to load developments in the Yukon, particularly mine-related loads at Faro, Keno, and Whitehorse. Yukon Energy acquired these hydro assets in 1987 as a result of the NCPC transfer.

- In 1952, NCPC built the Mayo Hydro facility to supply power to Mayo and UKHM in Elsa and Keno.

[2] Completion of the MD transmission line in 2002 materially further reduced diesel generation requirements in Yukon (by displacing diesel generation at Dawson). Figure 2.2 requires access to YECL generation data, which is not available after the years noted in the figure.

- In 1958, NCPC built the first two turbines at Whitehorse Rapids to supply the rapidly growing demand for power in Whitehorse.
- A third turbine was added to the Whitehorse Rapids plant by NCPC in 1969, along with the 138 kV transmission line from Whitehorse to Faro, as a consequence of an agreement between Cyprus Anvil Mining Corporation and Government of Canada to build a mining facility at Faro.
- In response to the Faro mine's power requirements and the opportunity to cost effectively displace diesel generation, the Aishihik hydro plant was developed by NCPC between 1973 and 1975, and the Whitehorse fourth hydro turbine generator was developed between 1982 and 1984.

Figure 2.3: YEC WAF Generation 1967 – 2004 details historic generation on the WAF grid. The majority of WAF generation has been hydro generation. During periods when the Faro mine was in operation there was also ongoing material diesel generation.

Figure 2.3:
YEC WAF Generation 1967 – 2004

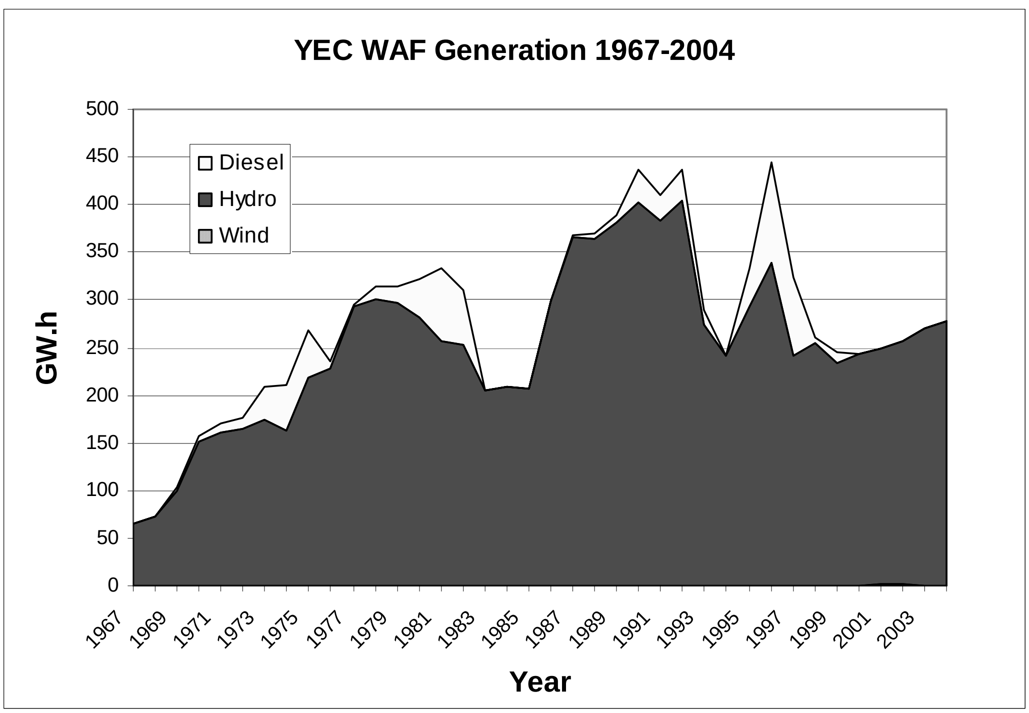
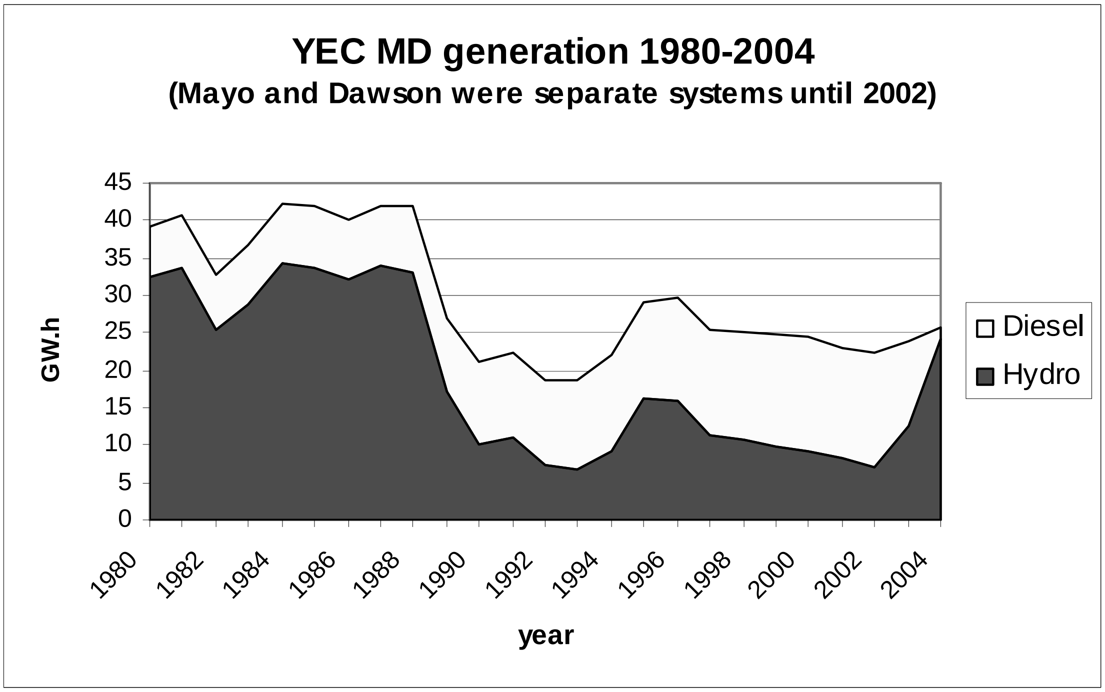


Figure 2.4: YEC Generation on MD 1980 to 2004 details historic generation in the communities that now form the MD grid. Until the UKHM closure in 1989, there was substantial hydro generation being used

(primarily at UKHM). Prior to completion of the Mayo-Dawson Transmission Line project in 2002, Dawson was a diesel served community; with completion of the MD grid, hydro generation has become the main source of generation for all MD grid communities. By 2004, only 6% of MD generation was by diesel.

Figure 2.4:
Generation on MD, 1980 – 2004



2.1.2 Transmission in Yukon

Yukon Energy owns and operates the WAF and MD transmission systems in Yukon of 69 kV or higher, as well as certain lower voltage lines; certain lower voltage lines (25 to 34.5 kV) are also owned and operated by YECL. The WAF and MD grids, and the other lines in Yukon are identified in *Figure 2.1: Map of Yukon Territory Power Infrastructure*.

The WAF and MD transmission lines are characterized as transmission lines because the lines transmit power from one community to another. However, due to the lower voltage, some of these transmission lines would be considered to be sub-transmission or distribution lines on a larger system.

WAF transmission is primarily a 510 kilometre 138 kV line that extends from Aishihik east to Whitehorse, north to Carmacks, and then east to Faro. Separate lower voltage lines connect other communities, comprising a 25 kV line (YEC) to Haines Junction, a 25 kV line (YEC) from Faro to Ross River, and a 34.5 kV system (YECL) southeast from Whitehorse to Teslin, Carcross, Tagish, Marsh Lake, Jakes Corner and Johnsons Crossing.

The MD grid is composed of a 223 kilometer 69 kV transmission line extending from the Town of Mayo to the City of Dawson, and connecting Stewart Crossing. A separate 69 kV transmission line connects to Keno and Elsa, northeast of Mayo.

2.2 OUTCOMES FROM THE 1992 REVIEW

Order-in-Council 1992/092 directed the YUB to review Yukon Energy and YECL (the “Companies”) major capital projects and contract commitment proposals required for non-diesel fuel generation, transmission and DSM to 1997. The 1992 Resource Plan submission prepared by the Companies was jointly submitted to the YUB, and provided the first opportunity since the NCPC transfer in 1987 to review long-range major capital planning options for Yukon power systems.

The 1992 Submission Overview provided a snapshot of an ongoing dynamic resource planning process, and proposed a set of ongoing demand and supply work plan elements for the 1992 to 2001 period rather than the development of a single resource option.

The YUB conducted a public hearing in October, 1992 to review the 1992 Resource Plan, and submitted a report (the “Capital Hearing Report”) with recommendations to the Commissioner in Executive Council on December 7, 1992 (Review of the Capital Resource Plans of YEC and YECL. Yukon Energy and YECL subsequently provided comments on the YUB’s forty-eight recommendations in Section 5.3 of the 1993/94 General Rate Application (“GRA”) Submission. Some of the notable recommendations are detailed below, along with responses by the Companies (as filed in the 1993/94 GRA), and updates on each recommendation:

A Framework for Capital Programs to be Pursued: The YUB’s Recommendations 1 and 2 stated that the Capital Hearing Report provided a framework for future capital projects, and that the capital resource plan should be reviewed as part of general rate applications, or as directed by the Board. The Companies agreed.

Yukon Energy and YECL provided updates to the YUB on capital planning activities as part of the jointly filed 1993/94 and 1996/97 general rate applications. Yukon Energy provided updated information on capital projects in *Section 5 of the 2005 Required Revenues and Related Matters Application*. The current Resource Plan Submission provides a further and more detailed update for the YUB.

Market Risks: The Companies agreed with Recommendations 3 and 4 that stated the significant market risk associated with the closure of the Faro Mine should be considered in assessing the Companies' Resource Plan and in determining the need for new facilities.

After the closure of the Faro Mine in 1998, there has been a significant WAF hydro surplus. As a result, there has not been a need for new facilities to address mining loads in Yukon. However, there are now new mining opportunities on the horizon for Yukon.

Potential mining loads are discussed in *Chapter Five: Industrial Development Scenarios and Opportunities*. Yukon Energy's assessment of new facilities in the context of mining loads takes into account the related risks.

Load Forecasts and Demand Side Management: The Board recommended that the low and base case scenarios should be considered in assessing the need for DSM (Recommendation 5).

The Companies agreed that DSM initiatives should not be based on the high case scenarios. Since the closure of the Faro Mine, there has been a hydro surplus, and the "high" case that the Board considered in 1992 does not exist at the present time (i.e., there is no industrial customer in Yukon today).

The Board also supported aggressive DSM activities to the extent that it can be demonstrated that the activities result in lower costs to consumers than alternate supply options (Recommendation 22). The Companies agreed that DSM activities should only be pursued where they are more economic than supply-side investments.

There is currently a hydro energy surplus in Yukon. The incremental cost to produce hydro generated electricity is virtually zero, and therefore there has not been a need on the WAF and MD systems to reduce energy use. As a result, both supply-side and demand-side conservation initiatives have not been a key focus for Yukon Energy since 1997.

In terms of managing the demand (customer consumption) on the system, the focus for Yukon Energy since the Faro Mine closure in 1998 has been primarily on developing interruptible energy sales opportunities on the WAF and MD systems (see *Section 2.3.2: The Growth of Secondary Sales*).

Recent DSM activities have been undertaken by the Energy Solutions Centre ("ESC")[3] . DSM options that reduce the load on the WAF system at the very immediate peak times (i.e., reduce the capacity requirement of the Yukon system) have the potential to provide value to Yukoners today. Programs that have been developed and tested by Yukon Energy and ESC since 1992 are explored in greater detail in *Section 2.4: Bulk Power Planning Since 1992*.

Load Factoring: The Board's Recommendation 11 recommended that the Companies perform studies and tests to determine the potential to use load factoring to increase the capacity relied on at the Whitehorse Rapids Hydro Plant.

The Companies continued to experiment with load factoring between 1992 and the 1993/94 GRA. The Companies maintained in the 1993/94 GRA that enhanced load factoring would not result in a firm capacity rating above 24 MW for Whitehorse during non-drought years. This item is further discussed in *Chapter 3*.

Load Forecasts and Use Per Customer: The YUB recommended a more rigorous approach to estimating residential and general service use per customer (Recommendations 7 and 8).

Yukon Energy and YECL did review the historical use per customer during the 1993/94 GRA. The average use per customer was expected to stay relatively constant. Consequently the driver in the load growth forecasts was the number of customers.

In the 1993/94 General Rate Application the Companies agreed to explore opportunities to carry out research pertaining to use per customer with the Yukon Government and others, and to document current electric heating use characteristics on the WAF system.

[3] The Energy Solutions Centre was under the management of the Yukon Development Corporation. On February 5th, 2005, the Yukon Territorial Government ("YTG") announced its plan to transfer management from YDC to YTG. Release #05-23, "New Model for Energy Solutions Centre to Improve Accountability", Online: http://www.gov.uk.ca/news/2005/05-23.html.

Yukon Energy and YECL also examined use per residential customer in the 1996/97 GRA. The Companies identified a trend of declining use per customer, and reflected this trend in the sales forecast. The decline in use per customer was attributed to a reduction in electric heat. The Companies suggested that higher electricity rates in the mid-1990s had encouraged conversions from electric heating.

Yukon Energy has factored a use per customer variable into its current load forecasting methodology for its retail customers. Yukon Energy's current load forecasts have two components: a measure of the increase in the number of customers; and a measure to reflect changes in the average use per customer. Yukon Energy's load forecast methodology is explained in greater detail in *Section 4.2.1: Non-Industrial Load Forecasts*. Due to its limited retail customer load, Yukon Energy does not have the data or analysis to weather normalize its past sales or forecasts for its own retail customers. Yukon Energy is not able to carry out analysis on customer numbers or use per customer on YECL's current retail customers.

Aishihik 3rd Turbine: The Board recommended in Recommendation 37 that the Companies pursue approval for the construction of the third turbine at Aishihik, given that it is economically, technically and environmentally feasible. The Board asked the Companies to "report back to the Board before commencing construction" and indicated that "the Companies should pursue installation of the maximum capacity that is economically, technically and environmentally feasible".

As of the 1993/94 GRA, the Companies were delaying activity on the third Turbine due to the closure of the Faro Mine at that time; similarly, active consideration of developing this project was once again delayed after the Faro Mine closures in 1997 and 1998. The third Turbine, however, remained a component of the Yukon Energy application for Aishihik relicencing throughout the period.

Yukon Energy received its renewed water licence at Aishihik in 2002 (which extends to December 31, 2019), including the environmental approval to install a third Turbine of up to 7 MW. Based on the current Resource Plan, Yukon Energy is now proceeding with the next steps in the Aishihik third Turbine project, including updated costing of the 7 MW installation and confirmation of hydrology.

Supply Options: In Recommendation 36 the Board stated that before pursuing construction of "large projects" (defined as projects with a cost of more than $5 million), preference should be given to DSM, small utility owned projects and Independent Power Producers ("IPP") that are cost effective for consumers.

In the 1993/94 GRA the Companies agreed with this option, providing that these options are cost effective for consumers. Yukon Energy's last internal large-scale Resource Planning exercise took place in 1996. In September, 1996, Yukon Energy requested Expressions of Interest from qualified parties interested in providing technologies, investments and/or partnerships to establish new generation facilities in Yukon to displace diesel generation. During that planning process, IPP projects were considered.

Independent Power Producers: The Companies agreed with the Board's Recommendation 45 that IPP's should be encouraged in Yukon, provided that there are no negative rate impacts on consumers. The Board recommended (Recommendation 47) that the Minister direct the Board to hold a hearing with respect to IPP policy and to develop a firm IPP policy for Yukon.

A hearing was not held. However, as noted above, Yukon Energy did solicit IPP proposals for development in 1996.

Feasibility Studies: Recommendation 39 stated that the Companies should not proceed with any feasibility studies for Drury Creek, Morley River, Lapie River and Orchay River, other than developing long-term hydrological data.

Yukon Energy has collected hydrological data, but has not proceeded with feasibility studies.

Coal: The Companies agreed with the Board's Recommendation 42 that studies of coal-fired generation should be limited to a review of coal technology, particularly with respect with plants under 20 MW.

Yukon Energy has not proceeded with any detailed study of coal technology. However, when Expressions of Interest were requested in 1996, three respondents focused on coal-based thermal generation for the WAF system. As a result of the closure of the Faro mine in 1997 and again in 1998, no projects were developed as a result of the call for Expressions of Interest.

Mayo-Dawson Transmission Line: The Companies agreed with Recommendation 42 that no further studies should be conducted on this transmission line unless demand changed sufficient to warrant a review of the project.

Escalating fuel costs and load growth subsequently led Yukon Energy to update its studies and ultimately commit to proceeding with the MD project in 2001 (including receiving the approval of the Minister). The

Line commenced operation in September of 2003, and has offset diesel generation and reduced fuel costs for Yukon Energy. For more information of the MD Transmission Line, see *Section 2.3.6: Mayo-Dawson Transmission Line*.

Wind: Recommendation 43 stated that research and development work should continue to be pursued with respect to wind generation. The 1993/94 GRA included the purchase and installation of a wind turbine on Haeckel Hill.

Yukon Energy has installed two research and development wind turbines at Haeckel Hill with a combined generating capacity of 800 kW.

2.3 MAJOR EVENTS AFFECTING POWER SYSTEMS SINCE 1992

There have been a number of significant changes to the Yukon system since 1992. The most notable of these changes include: closure of the Faro Mine; the increase in Secondary Energy sales; Yukon Energy's shift to direct management; the Whitehorse Rapids Generating Station fire rebuilding project; renewal of Yukon Energy's three water licences; and the construction of the MD Transmission Line. These events are outlined below.

2.3.1 Closure of the Faro Mine

After decades of operation on the WAF grid, including a number of closures and re-openings, the Faro Mine closed in 1998. This mine closure followed the 1989 closure of the United Keno Hill Mine ("UKHM"), which had been served by the Mayo hydro plant. As a result of the Faro Mine closure, there are currently no major industrial customers being served in Yukon. Major industrial customers are defined by Order-in-Council 1995/90 as, "a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer[4]."

Overall generation and diesel usage declined after the Faro Mine's closures in 1983 and 1993, 1997 and again after its final closure in 1998. When the Faro Mine was in operation, all of Yukon's hydro generation was absorbed by the system, and diesel generation was required on an ongoing basis. Since the final closure of the Faro Mine in 1998, there has been a hydro energy surplus on WAF.

[4] Rate Policy Directive, Order-in-Council 1995/90, May 29, 1995.

2.3.2 The Growth of Secondary Sales

Secondary Energy has been available from time to time to General Service or Industrial customers based on the availability of surplus hydro since before the NCPC transfer. Rate Schedule 32 – Secondary Energy, provides Yukon Energy with an opportunity to sell excess low-cost hydro power when it is available, but can interrupt secondary sales customers when it is likely that the utility will be required to generate electricity with diesel. There are now approximately 25 retail customers who together receive more than 20 GW.h of electricity under Rate Schedule 32. These customers use the electricity to displace fuel oil, and in some cases, propane.

The current Secondary Energy rate was approved in YUB Board Order 2005-12 at 66.7% of the equivalent energy price of fuel oil. The rate is adjusted quarterly to reflect ongoing market price adjustments for fuel oil.

Secondary sales have grown from 3,917 MW.h in 2000, to a forecast 20,613 MW.h for 2005. The recent growth in secondary sales can be attributed to the surplus in hydro energy on the WAF grid since the closure of the Faro Mine in 1998. Surplus hydro generation on the MD grid is also stimulating secondary sales on that system.

At today's rates, Secondary Energy sales are very beneficial, and help to pay for the fixed costs of the system (more than $1 million in revenues annually). However, although Secondary Energy are available from existing system assets, the generation system is not planned to provide service to secondary customers. For the purposes of planning the system for capacity requirements or energy projects, Secondary service is not included as required load to be served (however, in some cases the ability to enhance sales of secondary power can provided added economic benefits from certain projects).

2.3.3 Shift to Direct Management

On January 1st, 1998, Yukon Energy assumed full management and operation of its generation, transmission and distribution infrastructure and services. This includes direct responsibility for activities related to planning the Yukon integrated generation and transmission systems today.

Prior to 1998, Yukon Energy's assets had been managed by Canadian Utilities, a subsidiary of ATCO, which is YECL's parent company. Yukon Energy's billing service is the only service that is still provided by an ATCO company.

Yukon Energy and YECL are both regulated by the YUB. YECL was an active intervenor in the spring 2005 YUB hearing on Yukon Energy's *2005 Required Revenues and Related Matters* application. This was the first comprehensive revenue requirement submission that either had made to the YUB since the shift to direct management.

2.3.4 Whitehorse Rapids Generating Station Fire Rebuilding Project

On October 30, 1997, a fire started in the pump room of the Whitehorse Rapids generating station. The fire destroyed the generating station building, the system control centre, the Yukon Energy Corporate office, the switchgear, and caused superficial damage to hydro generators 1, 2 and 3. Even with the damage sustained by Yukon Energy, electrical service was not interrupted during the fire.

Yukon Energy filed insurance claims under its insurance provisions, and received a favourable settlement. The fire destroyed assets with a rate base of $2,280,000. A total of $11,604,000 of new assets were placed in service to replace the assets destroyed or damaged during the fire. A total of $1,799,000 in betterments were also completed. Yukon Development Corporation ("YDC") paid for $1 million of these costs. The balance of $799,000 was put into rate base.

The insurance claim resulted in a net benefit to ratepayers. Aging assets were replaced at essentially no cost to ratepayers. There was also a resulting insurance gain of $744,000.

2.3.5 Renewal of Water Licences at Whitehorse, Mayo and Aishihik

Yukon Energy is required to have water licences for the hydroelectric facilities that it owns and operates in Whitehorse, Mayo and Aishihik (near Haines Junction, Yukon). Water licences in the Yukon are issued for a period up to, but not exceeding 25 years. All of the water licences for these three facilities expired since the 1992 Resource Plan filing, and renewal of each licence has been obtained.

Whitehorse: The Whitehorse Water Use Licence (HY99-010) expired in 2000, and was renewed for 25 years (expires in 2025). It combines two prior licences, Marsh Lake and Whitehorse Rapids. The renewal of the licence was sought on the basis of no relevant changes being made to its terms and conditions, and included only administrative changes. The licence renewal was granted by the Yukon Territorial Water Board ("YTWB") on this basis. Dam safety monitoring requirements were formalized in the new licence. This was consistent with Yukon Energy practices and current Canadian Dam Safety Guidelines.

Mayo: Mayo Water Use Licence (HY99-012) expired in 2000, and was renewed for 25 years (expires in 2025). Similar to the Whitehorse facility, the renewal of the licence was sought on the basis of no relevant changes being made to its terms and conditions, and included only administrative changes, and the licence renewal was granted by the YTWB on this basis. Dam safety monitoring requirements were formalized in the new licence, which was consistent with Yukon Energy practices and current Canadian Dam Safety Guidelines.

Aishihik: Relicencing of the Aishihik hydroelectric facility took place over a number of years. It involved four amendments to the 1978 licence. A new licence with a Fisheries Act Authorization was issued in 2002 upon expiry of the 1978 licence. Yukon Energy had sought a new licence, and a 17-year licence was granted. Similar to Whitehorse and Mayo, the dam safety requirements in the licence are normal modern utility standards that would need to be completed whether a requirement of the licence or not. The renewal of the licence called for ongoing heritage payments, the construction of a boat launch at the north end of the lake, and an annual fish monitoring program.

New terms of the 17-year licence provide for a conditional seven-foot operating range subject to the terms of the Department of Fisheries and Oceans (“DFO”) Fish Act Authorization, and allow for the installation of a third turbine not exceeding 7 MW (subject to the requirement for YTWB approval of an operating plan when the third turbine is installed). Additional details on the Aishihik Licence renewal were provided in Interrogatory Response YUB-YEC-1-55 in Yukon Energy’s 2005 Required Revenues and Related Matters Application.

2.3.6 Mayo-Dawson Transmission Line

The MD Transmission Line Project came into service in September of 2003. The MD project was the first large-scale transmission infrastructure development project undertaken by Yukon Energy since the NCPC transfer in 1987. The 223 kilometre 69 kV transmission line links Mayo, a community with surplus hydro, with Dawson, a community that was previously served solely by diesel generation. The transmission line now supplies almost all of Dawson’s energy requirements. The line also provides hydro power to YECL at Stewart Crossing, which was previously served with diesel generation, as well as various locations along the North Klondike Highway that were not previously served by utility power.

The costs of the MD Transmission line were projected to be $35.6 million as of the end of 2005. A total of $5.8 million of this amount was provided by Yukon Development Corporation at no cost to ratepayers. YDC has also provided flexible debt financing to Yukon Energy. This financing ensures that ratepayers will be protected so that they are not paying, in any year, more than they would have paid had Dawson remained on diesel fuel generation[5].

2.3.7 System Upgrades and Changes

In addition to the completion of the MDTransmission Line project, and relicensing of its three hydro plants, Yukon Energy has undertaken additional system upgrades since the submission of the 1992 Resource Plan. Recent Upgrades include:

- Aishihik Unit #1 Rewind in 2003 (cost $1.2 million)
- Mayo Hydro Unit #1 and Unit #2 Capacity Increase in 2002 (cost $1 million)
- Addition of Wind Turbine #2 in 2000 (cost $2 million)

Yukon Energy has also been able to extend the service life of its three Mirrlees Blackstone base load diesel units located in its Whitehorse diesel plant (diesel units WD1, WD2 and WD3). WD3 is currently scheduled for retirement in 2007; WD2 is currently scheduled for retirement in 2009; and WD1 is currently scheduled for retirement in 2011. The 1992 Resource Plan had scheduled the retirement of WD1, WD2, and WD3 in 1998, 1998, and 2000 respectively. By 1996 the retirement was extended. After the Faro Mine closed, these units provided required reserve capacity for the system.

Since the Faro Mine closure in 1998, a 5 MW diesel unit was retired at Faro. Two diesel units with a combined capacity of 2 MW were moved to Mayo, and a 1.3 MW unit was removed from Faro to act as a mobile unit. The result is a decrease in the Faro diesel plant size from 13.6 MW to 5.3 MW.; in addition, two diesel units with a combined capacity of 1.3 MW were retired from Mayo.

2.4 BULK ELECTRICAL SUPPLY PLANNING SINCE 1992

Yukon Energy has been engaged in a number of power planning activities since the 1992 Resource Plan submission. In addition to the submission of the current plan, Yukon Energy has provided updates to the YUB in its rate and revenue application submissions. Yukon Energy's planning has included: developing an inventory of future supply options with YDC and BC Hydro; condition assessment work of its key generation and transmission assets; a review of the WAF and MD capacity criteria review; and work with ESC on DSM. Yukon Energy's significant power planning activities since 1992 are outlined in the following sub-sections.

[5] YUB Board Order 2005-12 approved $29.046 of the costs of the MD Transmission Line for inclusion into YEC's ratebase, net of the $5.75 million contribution by YDC ($0.05 million of the amount provided by YDC was an interest-free advance, not a contribution) and about $0.8 million being disallowed (amounts YEC cannot charge to ratepayers).

2.4.1 Ongoing Yukon Energy Infrastructure Planning Process

Infrastructure updates were provided as part of Yukon Energy's GRAs to the YUB in 1993/94, 1996/97, and in the *2005 Required Revenues and Related Matters* Application. These updates were in response to the YUB's Recommendation 2 from the 1992 Resource Plan hearing. The YUB recommended that the Companies' capital resource plan should be reviewed on an ongoing basis as part of general rate applications, or as directed by the Board.

2.4.2 BC Hydro Inventory of Potential Future Hydro Supply Options

YDC commissioned BC Hydro to work with YEC to conduct a Small Hydro Resource Study in 2002. The study included a review and assessment on existing information on hydro sites located in Yukon and relevant projects located in northern British Columbia. BC Hydro summarized over 200 sites which has provided Yukon Energy with a consolidated source for information on potential project options. The area studied included the WAF and MD transmission corridors, roughly 50 kilometres from the grids or highways. On WAF the study was extended from the current gird to Watson Lake along the Alaska Highway area.

2.4.3 Bulk Electrical Supply Infrastructure Condition Assessment Work

Yukon Energy commissioned three recent condition assessment studies. Acres International was commissioned to assess Yukon Energy's key transmission assets, while BC Hydro was commissioned to complete two studies: a study of Yukon Energy's key generating assets, and a study of selected substation assets. In May of 2004, BC Hydro completed its *Condition Assessment of Selected Yukon Energy Generating Assets*. BC Hydro's second report, *Condition Assessment of Selected Yukon Energy Corporation Substation Assets* was completed by BC Hydro in June of 2004. The Acres International report, *Assessment of Transmission Lines for Yukon Energy Corporation* was completed in December of 2003. A more thorough review of the findings from the condition assessments can be found in this Plan in *Section 3.1: Current Facilities Condition Assessment*.

Most of the assets examined by Acres International and BC Hydro were found to be in good to relatively good condition, and were expected to have operating lives of 20 additional years or more. The main exception is the Whitehorse Mirrlees diesel engines, which are further discussed in *Chapters 3 and 4*.

2.4.4 Generation Capacity Planning Criteria Review

There have been changes to the Yukon systems since the last detailed Yukon Utilities Board review of bulk system planning in 1992 as well as in the 1993/94 and 1996/97 GRAs including: closure of the Faro

Mine; growth in Whitehorse area loads; the interconnection of Mayo-Dawson; and the need to address the near term retirements of the Whitehorse Mirrlees engines. In combination, the above factors raised concerns regarding the ability of the assets in the Whitehorse area to serve the city in the event that the Aishihik Line was out of service for a substantial period during the winter peak. As a result, Yukon Energy undertook a review of the Capacity Planning Criteria.

For the Whitehorse area capacity, one specific issue was to determine how to approach the pending retirement of 14 MW of nameplate capacity for three Whitehorse Mirrlees diesel (WD) units (WD1, WD2 and WD3). Reviewing the adequacy of capacity planning criteria is a prudent first step prior to making (or rejecting the need to make) any such new capital investments.

NWT Power Corporation recently undertook a similar review of their Yellowknife grid. NWT Power Corporation commissioned a study of their capacity planning criteria by Dr. Billinton from the University of Saskatchewan. The NWT Power Corporation received approval from its regulator for its revised capacity planning criteria in November of 2004.

Yukon Energy retained Drs. Billinton and Karki from the University of Saskatchewan to study the key areas and characteristics of the Yukon systems (focused on WAF) relevant for a review of the required firm capacity planning criteria. As part of the capacity criteria review, Yukon Energy worked with Drs. Billinton and Karki to develop recommendations on capacity planning criteria for the Yukon systems. The conclusions from that work are detailed in *Section 3.3: Capacity Planning Criteria Review*.

2.4.5 Demand Side Management and the Energy Solutions Centre

Section 2.2: Outcomes from the 1992 Review touched on Yukon Energy's approach to DSM. When the Faro Mine was in operation, hydro generation was fully utilized and Yukon Energy actively pursued DSM opportunities in order to save diesel generation costs. The Faro Mine closures shifted Yukon Energy's focus away from DSM due to surplus diesel generation costs. After the final closure of the Faro Mine in 1998, the focus on DSM activities decreased greatly. The key activities from the 1992 to 1998 are outlined below.

DSM From 1992 to 1998

Smart Home on Wheels Community Tour: In 1992 the Companies developed a Smart Home on Wheels Community Tour to educate Yukon residents and retailers outside of Whitehorse of the benefits of Power Smart products. This program was intended to parallel the impact of The Power Smart Idea

Shop which was located in Whitehorse. Between October 26 and December 14, 1992, the Tour visited the communities of: Burwash Landing, Beaver Creek, Carmacks, Pelly Crossing, Teslin, Haines Junction, Mayo, Stewart Crossing, Dawson City, Carcross, Tagish, Watson Lake, Ross River and Faro. Fifteen presentations were made to local schools, and over 500 people visited the trailer. A survey was completed by the majority of visitors to the trailer, and 99% of respondents indicated that they learned something new about energy management. A further 85% identified steps that they planned to take to reduce energy consumption.

Home Smart: In March 1993 Phase one of the Home Smart program was completed. The program provided subsidies on six energy-saving and energy efficient products, including: outdoor timers, water saver kits, water tank wraps and pipe insulation, power cord savers, compact fluorescent light bulbs and compact fluorescent hardware fixtures. The program was retail focused, and 59 Yukon retailers participated by carrying Power Smart products, information displays and information.

Energy Management Working Group: On November 1st, 1996, Yukon Energy and YECL submitted a Final Report to the Yukon Utilities Board on the activities of the Energy Management Working Group. The group was formed as per Item 4 of the 1996/97 GRA Settlement, as approved by the Board in Order 1996-7. The parties who participated in the process included:

- Utilities Consumers' Group
- Yukon Housing Corporation
- Yukon Energy/YECL
- Yukon Chamber of Mines
- Whitehorse Chamber of Commerce
- City of Whitehorse
- The Government of Yukon

The Report identified work in progress that Yukon Energy and YECL set to achieve within the 1996/97 GRA period. The activities noted were:

- Education to the general public via bill stuffers, trade shows, etc.
- Opportunity assessments completed for customers on request
- An Opportunity Assessment was completed for Anvil Range Mining Corporation and paid for by Yukon Energy
- Opportunity Assessments were completed by YECL for the City of Whitehorse and Town of Haines Junction to train their employees

- YECL committed to investigate and study programmable electric hot water controllers to shift the peak load
- Yukon Energy planning a "Opportunities Assessment" of their plants
- Studies on capacity enhancements were scheduled for 1997
- YECL committed to start a more aggressive energy management initiative with its major users
- Rebate programs for residential customers were scheduled for study in 1997

Demand Side Management Since 1998

Since the closure of the Faro Mine in 1998, there has been a hydro energy surplus. Consequently there has been minimal economic justification to pursue DSM initiatives for most Yukon assets. However, DSM programs have not been terminated.

Since 2000, management of DSM programs has been undertaken by the ESC. ESC is a service and program delivery agency for energy efficiency and green power programs for the Federal and Yukon governments. The programs run by ESC include electricity programs, and programs focussed on improving the energy efficiency of other energy sources, such as wood-burning. As reported by ESC, the ESC programs that specifically address electricity conservation include the following:

2002-2003 Fridge Exchange: A Pilot Project of Yukon Development Corporation and Natural Resources Canada: The program encouraged Yukoners to exchange fridges that were 10-years old or more, for new, and more energy efficient ENERGY STAR fridges. Yukoners were responsible for purchasing the new appliances, however incentives were given. The program resulted in the following savings:

- 58 reduced tonnes of CO_2 generation
- 72 megawatt hours of savings
- $14,400 in avoided costs

Final Report to Climate Change Action Fund Public Education and Outreach, Completed June 2001: The program targeted 2,000 house call energy audits. A total of 1,457 homes were visited. The program focussed on low flow showers to reduce water heater use; water heater blankets; and higher efficiency bulbs. The program resulted in:

- 2,203 reduced tonnes of CO_2 generation
- 2,938 megawatt hours of savings

"Six Pack" Parking Lot Controller Pilot Project: A 2003 study of Intelligent Parking Lot Controllers in six Whitehorse locations: This pilot project evaluated the use of a block heater conservation device that limited the number of hours that block heaters would be in use during the business day. The test year that was used for the analysis was a warmer than average year which reduced the savings realized during the year. The total savings realized were 6,426 KWh. However, the payback period for the equipment was very difficult to forecast.

Penguin Pilot Project: Assessing the acceptability of residential tank timers: Results and Evaluation report, December 2003: The pilot project evaluated timers on residential water heaters. The bulk of the water heaters in the pilot project were 40-gallon capacity, with two 3,000 watt elements. The pilot project included 50 hot water tanks, and had a combined load of 150 KW.

The GreenHog Handbook: The handbook was launched in March 2004 by ESC. The handbook solutions to reduce greenhouse gas emissions in the Yukon. The 50-page handbook includes information on climate change, practical tips and solutions for lowering greenhouse gas emissions, coupons for free and discount items, and a booster card for discounts on locally available products and services. This handbook provides a number of suggestions and detailed information, but it is difficult to calculate the greenhouse gas emissions reduced due to this program.

3.0 SYSTEM CAPABILITY

In order to begin an effective resource planning exercise, it is necessary to assess the capability of the existing system to supply loads today and into the future under various time horizons and scenarios. This includes assessing the condition of Yukon Energy's assets, their capability to provide capacity and energy to the system, and ensuring that an adequate capacity planning criteria for the system is in place. This chapter provides a review of the condition and output of Yukon Energy's assets, and Yukon Energy's new capacity planning criteria.

The sections for this chapter are as follows:

- Section 3.1 Current Facilities Condition Assessment
- Section 3.2 Capacity and Energy Output of Existing Facilities
- Section 3.3 Capacity Planning Criteria Review
- Section 3.4 Summary: Revised Capacity Planning Criteria

The condition assessment section contains a description of three recent condition assessment reports requisitioned by Yukon Energy, and the findings of the assessments.

The capacity and energy output of the existing facilities are reviewed in the second section, which focuses on implications of changes to major asset output since 1992, either from age, enhancement, or licencing conditions.

The capacity planning criteria review section provides an overview of Yukon Energy's past capacity criteria, and the new capacity criteria that was recently adopted. Yukon Energy's past criteria was developed by NCPC, adopted in 1987 when Yukon Energy acquired NCPC's assets, and modified slightly in 1992. Yukon Energy reviewed its capacity criteria in 2004-2005 to determine if the criteria still reflects the needs of the Yukon system, and concluded that changes are required as set out in Section 3.4.

3.1 CURRENT FACILITIES CONDITION ASSESSMENT

Yukon Energy has recently had independent assessments of its key generation, substation and transmission assets.

- In May of 2004, BC Hydro completed its *Condition Assessment of Selected Yukon Energy Generating Assets*. This assessment was focused on Whitehorse Hydro (Units WH1 through

WH4), Whitehorse Diesel (Units WD1 through WD7) and Aishihik Hydro (units AH1 and AH3). The condition assessment did not review the other diesel plants or the Mayo hydro facility.

- A *Condition Assessment of Selected Yukon Energy Corporation Substation Assets* was completed by BC Hydro in June of 2004. The focus of BC Hydro's assessment was on circuit breakers and transformers located at the substations at Aishihik, Takhini, MacIntyre, Whitehorse (all on WAF) plus Mayo.
- Acres International was commissioned to assess Yukon Energy's transmission assets. The Acres International report, *Assessment of Transmission Lines for Yukon Energy Corporation* was completed in December of 2003. The condition assessment by Acres International of Yukon Energy's transmission lines was of a significantly different type than the Generation and Substation assessments. In the Acres assessment, the primary item to be addressed was the expected remaining life of the transmission assets, based on a sampling of the WAF transmission lines.

The three reports were filed in YEC's 2005 Required Revenues and Related Matters Application as Interrogatory Response YUB-YEC-A52. BC Hydro and Acres International found Yukon Energy's assets to be in good to relatively good condition with a few notable exceptions:

- Whitehorse Diesel Units WD1, WD2 and WD3 were assessed to be at their "end of life" and either need to be retired, or require substantial investment;
- Mayo Substation transformer T1 needs to be replaced in the next five years; and
- A number of circuit breakers need to be replaced at various substations.

Other smaller projects for modernization or life extension were also recommended in the various condition assessments.

3.1.1 Yukon Energy's Response to Condition Assessments

As a result of the condition assessment documents, Yukon Energy developed short to medium term capital investment plans to address the bulk of the items identified by BC Hydro and Acres International. This Yukon Energy plan was provided in the 2005 Required Revenues and Related Matters Application and has been reviewed by the Yukon Utilities Board. To summarize:

- **BC Hydro Condition Assessment of Selected Yukon Energy Generation Assets:** As shown in the Table 3.1, the BC Hydro report recommended $2.454 million in work on these units. Yukon Energy's capital plan for these same units over the period 2004-2009 reflects overall approximately the same scope of work (also shown on Table 3.1). Yukon Energy's plan consists of $3.760 million. The reason for the $1.306 million variance is primarily material costs associated with the WH1 and WH2 trunion bushing capital projects that were not forecast by BC Hydro for $824,000, plus a 2004 project for major capital work on WD5 for $201,000 that was already in progress when BC Hydro prepared their report (and therefore is not addressed in the BC Hydro recommendations).

- **BC Hydro Condition Assessment of Selected Yukon Energy Corporation Substation Assets:** In this report, BC Hydro reviewed a number of Yukon Energy's substations and recommends $921,000 in work over the "medium to long-term" at Appendix I of their report (also see Table 3.2). Yukon Energy's capital plan for 2004-2006 includes $880,000 to complete this work, including further detailed assessment of each of the recommendations. YEC intends to review other options before proceeding with circuit breaker replacements estimated at $210,000.
- **Acres International Assessment of Transmission Lines for Yukon Energy Corporation:** Although some token amounts were identified as being recommended as capital to be spent in the next five years ($43,000 per page 28), the majority of the report was not aimed at determining the appropriate capital investment in transmission line. Yukon Energy has incorporated the amounts identified by Acres International in its five year capital plans for transmission spending.

Table 3.1:
BC Hydro Generation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s)[1]

BC Hydro 5 year Recommendation

	P125	P126	P127	AH0			
Unit Life Extension Mech	$152	$438	$84	$22			$696
Unit Life Extension Elect	$20		$40	$130			$190
Plant Life Extension Mech	$37	$245	$0	$8			$290
Plant Life Extension Elect	$10	$4	$43	$15			$72
Unit Modernize Mech	$92		$55	$181			$328
Unit Modernize Elect	$70		$120	$160			$350
Plant Modernize Mech	$48		$40	$80			$168
Plant Modernize Elect	$50		$10	$300			$360
	$479	$687	$392	$896	$0	$0	**$2,454**

YEC Budget Planning

	2004	2005	2006	2007	2008	2009	
P126 Diesel Life Ext (Mech)	$201						
P126 Diesel Life Ext (Elect)	$19						
Generation Unit Life Mech		$75	$75	$250	$150		
Generation Unit Life Elect		$75		$100			
Plant Life Mech					$250		
Plant Life Elect			$50				
Unit Modernize Mech					$250		
Unit Modernize Elect			$50		$250		
Plant Modernize Mech				$150			
Plant Modernize Elect				$250	$100		
P125 Vibration Monitoring	$120	$60					
P125 Trunions	$504	$400					
P127 Exciter Assessment		$21					
P127 Unit Mech Overhaul				$350			
P127 Ventilation		$10					
	$844	$641	$175	$1,100	$1,000	$0	**$3,760**

Notes:
YEC budget does not align with BC Hydro recommendations due to:
YEC not in full agreement all work is appropriate, and costs estimates are different between BC Hydro and YEC.

[1] P125 is Whitehorse Hydro plant containing units WH1, WH2 and WH3; P126 is the Whitehorse diesel plant; P127 is the hydro plant containing WH4; AH0 is Aishihik.

Table 3.2:
BC Hydro Substation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s)

BC Hydro Medium and Long Term Recommendations

	S249	**S150**	**S164**	**S167**	**S171**	**General**	
Transformer Replace	$150						
Circuit Breaker Replacements		$210					
Vertical Break Switches			$130	$130			
Disconnect Replacements		$30					
Station Service Upgrade			$60		$60		
Insulation Coordination Study						$30	
Circuit Breaker Analyzer						$18	
Infrared Digital Camera						$3	
Stock Inventory						$100	
	$150	$240	$190	$130	$60	$151	**$921**

YEC Budget Planning

	2004	**2005**	**2006**	**2007**	**2008**	**2009**	
Transformer Replacement			$200				
Station Service Upgrades				$150			
Breaker Analyzer		$40					
Transformer Leveling		$40					
Substation Follow Up Work		$150	$150	$150			
	$0	$230	$350	$300	$0	$0	**$880**

Notes:
Only YEC plans that correlate to the BC Hydro report are shown here. Other work is planned for substations or components that BC Hydro did not assess.

3.1.2 Condition Assessment Findings Relevant to Resource Planning

The Condition Assessment findings indicate Yukon Energy's system is generally well suited to meeting the future WAF and MD system load requirements over the duration of the Resource Plan within the as-built capabilities of each the various units studied. Aside from new requirements related to load growth, the clear exception is the three Whitehorse Mirrlees diesel units, WD1, WD2, and WD3, located at the Whitehorse diesel plant.

It has been well known to Yukon Energy that the Mirrlees units were approaching retirement, and in fact earlier Yukon resource planning exercises (both 1992 and 1996) were based on these three units being retired prior to 2006. The units have been retained in-service due to the current system load, which has not required material running time for these three units during the 1993-1995 closure, or since the 1998 closure of the Faro mine and into the future until at least the current hydro surplus on the WAF system is consumed by firm load.

The issues and options relating to the requirement to retire the Mirrlees units are further addressed in *Chapter 4.*

3.2 CAPACITY AND ENERGY OUTPUT OF EXISTING FACILITIES

The generating assets in service are required to meet both capacity (instantaneous peak) and energy (annual and sometimes seasonal requirements) of the individual systems (WAF, MD, isolated). An overview of Yukon Energy's generating assets is set out in Table 3.3. On each of the WAF and MD grids, supply is also available from diesel and, in one case, hydro assets owned by YECL.

This section reviews the capability of key Yukon generation assets to meet capacity and energy requirements of the various systems.

The capacity ratings of Yukon Energy's assets reflect design or "nameplate" ratings, as adjusted in certain cases to reflect the real-world conditions with respect to the individual unit, or conditions that exist at the time of year when capacity requirements are highest (e.g., winter). Capacity ratings for resource planning also must reflect what can be relied upon in worst case conditions, in particular drought conditions for hydro units.

Energy ratings could similarly be developed to reflect reliable output in worst case conditions (such as a drought for hydro units). However, given the current surplus energy conditions on the two main Yukon systems, energy output is only addressed in this section with respect to Aishihik, which has been moderately affected by recent changes to the Water Licence under which it operates.

Table 3.3:
Yukon Energy Generation Inventory

Location	Unit No.	Type	Manufacturer	Mover Model	Name Plate Capacity	MCR Rating (kW)	In-Service Date	Planned Retirement Date
Aishihik						30,000		
	AH1	hydro	Dom Eng.	Francis	15,600	15,000	1975	none
	AH2	hydro	Dom Eng.	Francis	15,600	15,000	1975	none
Faro						5,300		
	FD3	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	FD5	diesel	Caterpillar	3516	1,400	1,300	1990	2020
	FD7	diesel	Caterpillar	3612	3,000	3,000	1992	2027
Dawson						5,000		
	DD1	diesel	Caterpillar	3512	800	800	1988	2018
	DD2	diesel	Caterpillar	3516	1,000	1,000	1987	2017
	DD3	diesel	Caterpillar	3516 TA	1,000	1,000	1990	2020
	DD4	diesel	Caterpillar	D399	700	700	1975	2005
	DD5	diesel	Caterpillar	3606	1,500	1,500	1996	2031
Mayo						7,400		
	MD1	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	MD2	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	MH1	hydro	Dom Eng.	Francis	2,620	2,600	1957	none
	MH2	hydro	Dom Eng.	Francis	2,840	2,800	1951	none
Whitehorse						62,400		
	WH1	hydro	K.M.W.	Kaplan	5,800	5,800	1958	none
	WH2	hydro	K.M.W.	Kaplan	5,800	5,800	1958	none
	WH3	hydro	C.A.C.	Propeller	8,400	8,400	1969	none
	WH4	hydro	Dom Eng.	Propeller	20,000	20,000	1984	none
	WD1	diesel	Mirrlees	KV12	3,920	3,000	1968	2011
	WD2	diesel	Mirrlees	KV16	5,150	4,200	1968	2009
	WD3	diesel	Mirrlees	KV16	5,150	4,200	1970	2007
	WD4	diesel	EMD	20C	2,500	2,500	1975	2025
	WD5	diesel	EMD	20C	2,500	2,500	1975	2025
	WD6	diesel	EMD	20C	2,700	2,700	1990	2025
	WD7	diesel	Caterpillar	3612	3,300	3,300	1991	2026
Haeckel Hill						810		
	WW1	wind	Bonus	MARK III		150	1993	2013
	WW2	wind	Vestas			660	2000	2020
Mobile Diesels						1,450		
	YM1	diesel	Caterpillar	3516	1,400	1,300	1990	2015
	YM2	diesel	J Deere		150	150	1999	2024
Total Capacity						**112,360**		

3.2.1 Whitehorse Rapids Hydro Firm Capacity

The largest generating station in Yukon is the Whitehorse Rapids hydro plant. The output of the plant at full river flow conditions in summer is 40 MW, or slightly above. However, during low flow (i.e., drought) winter periods, the plant's firm output that can be relied upon is well below this level.

Whitehorse hydro is supplied by the flows of the Yukon River. The plant is largely "run-of-the-river", but there is some modest flow control via a control structure at the outlet of Marsh Lake (the Lewes Dam). By managing the flow out of Marsh Lake in accordance with licence conditions, Yukon Energy can help sustain Yukon River flows into the winter periods when system load requirements are highest. Absent this control, the plant would have very low firm winter output. Although YEC has a modest level of flow control on the river, there is very limited ability during winter to use the Whitehorse Rapids plant for "load factoring" where the plant output might be materially varied on (say) a daily basis. In summary, "load factoring" types of fluctuation in downstream flows at this plant during winter conditions can cause ice break-up and ice jamming, and consequently flood low-lying areas of Whitehorse, as was reviewed in detail by the YUB at the 1992 Resource Plan hearing.

The Whitehorse Rapids reliable firm capacity rating during low winter flows was reviewed in 1992 and in follow-up at the 1993/94 GRA (as set out in Chapter 2). In short, at that time Yukon Energy and YECL provided evidence that during drought years, a managed drawdown of Marsh Lake over six months can provide 19 MW of consistent firm capacity under the lowest flows on record. However, Yukon Energy also indicated that in 80% of the years (i.e., non-drought years), the plant could reliably provide 24 MW or more during winter. In 1992, the Companies indicated that in drought years, if 24 MW of plant capacity was required, up to 5 MW of diesel may be able to be temporarily leased for the winter to maintain a 24 MW reliable level of capability at this plant (over and above the capability provided by the plant's existing diesel units). As a result, since that time the hydro units at this plant have been assigned a winter reliable capacity rating of 24 MW.

Yukon Energy has continued to refine its operation of the Whitehorse Rapids hydro plant, particularly in the period since the closure of the Faro mine. Based on these more recent reviews, Yukon Energy can now confirm that the drought-year capability of the Whitehorse Rapids plant is 24 MW under current load conditions. This is achieved largely by being able to maximize Marsh Lake outflows, starting November, at a stable level for the four coldest winter months, and at licenced minimum flows for the remaining two winter months (when capacity is less of a concern on the WAF system). In addition, Yukon Energy can manage Schwatka Lake levels to a small degree on a daily basis, drawing down the lake by about six inches during the day and allowing it to refill at night.

Consequently, Yukon Energy continues to use 24 MW as the firm capacity of the Whitehorse Rapids plant. Moreover, this full level is now achieved without the earlier concept of resorting to short-term leased diesel units during drought conditions.

3.2.2 Aishihik Hydro Capacity and Energy

Unlike Whitehorse Rapids, Aishihik hydro capacity output is not limited by water storage or droughts. This is because the multi-year Aishihik reservoir is large and quite flexible (with a seven foot restricted operating range under the renewed licence), and can be dispatched largely as needed by Yukon Energy to meet peak loads. For this reason, Aishihik's output can vary substantially during the day in winter as loads change (compared to Whitehorse hydro, which is a very stable daily output). Aishihik's output also varies materially on a seasonal basis, as summer use is minimized to allow the lake to re-fill for the coming winter.

The maximum capacity output of Aishihik hydro is 30 MW today, based on 2 – 15 MW units. For the reasons noted, this capability is available on a firm basis during winter low flow conditions.

Recent rewinds performed on AH1 indicate a potential to increase the rating on the units to 15.4 MW. However, rewind work has not yet been performed on AH2 (scheduled for 2006) and until this is completed and consequent coordinated testing done on the units, YEC will not be able to confirm the slight increase in capacity ratings. Future potential also exists to re-runner the Aishihik units to theoretically increase the mechanical capacity output by as much as 20%; however this initial indication requires significant further work to confirm that the electrical system and various physical components (such as wicket gates and turbine bearings) can handle the increase in output. This preliminary assessment work is ongoing.

In terms of annual energy capability, due to the multi-year characteristics of the Aishihik plant and how it is used, the long-term annual energy output of Aishihik is dependent upon a combination of (a) long term average flow conditions, (b) load requirements on WAF, and (c) the constraints relating to the facility's capacity and its water licence terms and conditions. For the purposes of this Resource Plan, Yukon Energy has retained the Aishihik long-term average output at 105 GW.h/year consistent with previous plans. As noted below, this capability is expected to increase slightly should sufficient major new industrial loads be placed on the system; however, under such increased load conditions, Aishihik's energy long term average capability is currently estimated to be about 3 GW.h/year lower than it would have been had the previous licence conditions (nine foot unrestricted operating range) been maintained.

- **Current WAF Load Conditions:** At present, given surplus hydro energy on WAF due to current load conditions, Aishihik Lake is being maintained in a substantially full condition near the top end of its licence limits, so any major increase in need to drawdown the lake (such as for major new loads) will allow high output for some time before the stored energy is consumed (similarly, drought conditions at Aishihik today can be addressed by a period of drawdown to maintain long-term average generation levels despite low inflows). Under these conditions, the earlier long-term average energy capability does not appear to be materially affected by the new Water Licence terms and conditions.

- **Major Industrial Load Additions:** At such time as sufficient large new industrial load develops on WAF, similar to the Faro Mine loads in the past (or greater), it is to be expected that Aishihik Lake would tend over a few years to be drawn-down to within the mid-range of its licenced operating range. After such drawdown, Aishihik's long-term average annual energy output is expected to increase slightly above 105 GW.h/year and to reflect licence conditions. In the event that sufficiently higher WAF industrial loads occur, this long-term average energy capability is expected to be somewhat further increased, but also to be as much as 3 GW.h per year lower under the current seven foot restricted operating range than would be expected under the nine foot unrestricted operating range of the reservoir with the previous Water Licence.

3.2.3 Mayo Hydro Capacity

The capacity of the Mayo hydro plant has traditionally been listed as 5 MW based on 2-2.5 MW turbines. However, there has not been sufficient load on this system for many years to make use of this full capacity.

Due to the age of the units, in the last few years Yukon Energy has re-runnered and rewound the units which has enabled an increase in individual unit performance (now rated at 2.6 and 2.8 MW respectively). For planning purposes, Yukon Energy has assumed the combined 5.4 MW can be generated at the plant. It is important to note, however, that there is not sufficient load today to bring both units simultaneously up to full load to determine whether the full 5.4 MW can be achieved. This testing cannot occur until further load growth occurs on the Mayo-Dawson system. The increase in capacity is also forecast to increase the long-term average energy from 40 to 42 GW.h/yr.

3.2.4 Whitehorse Diesel Capacity

As noted in Section 3.1, there are immediate issues with respect to determining the future of the Whitehorse diesel plant in light of requirements to either retire or invest substantially in the Mirrlees diesel units WD1, WD2, and WD3.

In the interim, the three units are not in a condition that can sustain a Maximum Continuous Rating ("MCR") for planning purposes to the full nameplate ratings of these units. As a result, Yukon Energy has based its near-term planning on a "de-rated" MCR for these units of 4.2 MW (WD 2 and WD3, nameplate ratings of 5.15 MW) and 3.0 MW (WD1, nameplate rating of 3.92 MW).

Should some form of life extension project be undertaken on these units, that project would need to re-assess the ability to bring these units back up to the full nameplate MCR.

3.2.5 Fish Lake Hydro (YECL) Capacity

YECL maintains a small two unit hydro facility on the WAF system called Fish Lake, rated at 1.3 MW. Fish Lake hydro is neither dispatched nor monitored by Yukon Energy, and cannot be readily adjusted to match load conditions on a daily basis.

Fish Lake has traditionally been included in the Yukon planning process as firm capacity on the WAF system, at 1 MW. However, recent reports on the output of Fish Lake indicate winter flows cannot be relied upon to sustain outputs higher than about 400 kW, as was the case through the monthly averages during the winter of 2003/04 (December of that year dropped to a monthly average output of 389 kW), with many recent winters not recording average monthly outputs above about 600-700 kW.

Consistent with normal system planning practice of recognizing winter constraints, as is done for Yukon Energy's assets, the YECL Fish Lake facility are considered in this Resource Plan to be reliable firm winter capacity at a maximum of 400 kW.

3.3 CAPACITY PLANNING CRITERIA REVIEW

The Yukon system capacity planning criteria are the sets of rules used by YEC to determine how much firm generation capacity is required on the various Yukon systems and when additions to generation capacity are required. Criteria are applied separately for each power system in Yukon, e.g., the WAF system versus each isolated diesel system.

Changes to the Yukon systems since 1992, as well as the pending retirement of the three Mirrlees diesel units at Whitehorse, prompted a re-examination of the capacity planning criteria, focused particularly on WAF. As a result of this re-examination, Yukon Energy has adopted new capacity planning criteria.

Adequate firm generation capacity is one component of providing reliable power. Overall reliability of each BES system (generation and transmission) requires:

a) that there is adequate firm generation (and transmission) capacity installed on the system;
b) that the installed system be properly protected;
c) that the installed system be properly maintained (including brushing of transmission lines); and,
d) that the installed system is operated and dispatched in accordance with sound operating criteria.

In addition, the reliability of service to customers served on the distribution system will also include various factors relating to the reliability of that lower voltage system as well.

Standard utility reliability tests are intended to cover all of the recognized factors affecting system generation supply reliability including load factor growth both on a system and on each feeder, maintenance of equipment, regular and routine servicing and repair, assessing remaining life, planning for end of life replacement, removal of danger tress, and a range of other specific factors that affect reliability.

Capacity criteria in regards to long-term BES resource planning deals only with the first item in the above list of factors affecting BES system reliability; namely, that there be adequate firm generation and transmission capacity installed on each system.

In assessing capacity planning, it is recognized that Yukon Energy policy first interrupts secondary energy service that is to be supplied by surplus hydro resources, and that no BES capability is planned to supply secondary energy service. All remaining “firm” customer load requirements at the time of system maximum load or peak (e.g., winter peak on WAF) are considered when assessing each system’s capacity planning requirements.

3.3.1 Background and Overview on the Evolution of Capacity Planning

Planning of a utility system must provide both for system growth and for operation after a component failure. Systems vary greatly in size and complexity but the ability of each system to maintain service is compared by using established and recognized criteria.

In general, throughout various systems these planning criteria have evolved gradually into more defined ratios as systems have grown bigger and more complicated. Where relevant, transmission reliability has also been addressed where it directly affects generation reliability.

The criteria used by NCPC were developed to indicate the required amount of firm generating capacity to cover relatively small isolated systems, and were consistent with utility planning standards of that era. NCPC had started with a multiple of small isolated systems, some of which continue, but others had grown to the point where multiple sources were interconnected.

Yukon Energy (and its then manager, YECL), as the operator succeeding NCPC for the Yukon, initially followed the practice of NCPC. It was quickly found that the continuing small isolated installations were reasonably covered by the NCPC criteria but that the larger systems with multiple sources needed more detailed analysis to be secure:

- The small systems were considered to be adequately protected if the generating capacity with the largest single unit out of service was at least 110% of the anticipated peak load. This approach is continued today.
- For the larger "grid" systems, it becomes necessary to consider not only the possible loss of a single generator (in the case of WAF, a single "wheel" at Aishihik), but also the likelihood that at least one of the major WAF diesels would be unavailable at the same time. Consequently, the Resource Plan in 1992 introduced recognition of the diesel-related effect on Yukon Energy's ability to serve any particular WAF load by adding a "10% of installed diesel" reserve on top of the Aishihik hydro reserve.

Under the NCPC capacity planning criteria and the 1992 Resource Plan criteria, the transmission system availability was not considered at all.

In the meantime, other integrated utilities developed a statistical approach to the potential interruption of service for any customer. This is often evaluated as the Loss of Load Expectation ("LOLE") and it is measured in hours per year[2]. Most of the various Canadian utilities have come to apply an LOLE range from one to two hours per year as their capacity planning standards. Where relevant, certain utilities have incorporated transmission into this assessment where generation reliability is directly and materially affected by transmission. Specific recent experience with Northwest Territories Power Corporation has

[2] Other terms are also used to describe the probabilistic measures, such as the BC Hydro criteria of Loss of Load Probability ("LOLP") or Newfoundland and Labrador Hydro's Loss of Load Hours ("LOLH").

also applied, in parallel with LOLE criteria a second test to ensure that customers are protected against failure of any single system component.

Yukon Energy has recently examined the LOLE approach and tested it against the operating history of its WAF system. This review has shown that the WAF system has substantial hydro generation availability that is directly affected by certain transmission, and that 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 has therefore now 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.

At the same time, Yukon Energy has recognized that the LOLE function is an average that does not indicate how long any particular outage will last, and that any extended outage on its grid systems during the winter peak could be very adverse and serious, particularly for affected residential and commercial customers. Yukon Energy has addressed this concern by considering in parallel with LOLE a second test as part of its planning criteria, namely the effect of the failure of any individual bulk electrical system component and the ability of the system to continue to serve its firm residential and commercial customers without the failed component (i.e., a test described as “surviving the first failure” or “operating in the N-1 condition where “N” is the normal system complement). As an example, the biggest loss of generation on WAF today at winter peak would be 30 MW following a failure of the Aishihik transmission line; this loss would be far greater than the loss during winter peak of the biggest generator (which currently is a 15 MW generator at Aishihik)[3].

The previous criteria, the recent review and the revised criteria now adopted by Yukon Energy are each reviewed in more detail below.

3.3.2 Yukon Energy’s Previous Capacity Planning Criteria (prior to late 2005)

The Yukon systems were previously planned with criteria (as reviewed in 1992) using a single formula for specifying its required firm generation capacity on each type of system. This deterministic criteria was outlined in the 1992 Resource Plan.

[3] The largest single unit on the WAF system is WH4, one of the hydro units at Whitehorse. However, as Whitehorse has four hydro units (WH1 at 5.8 MW, WH2 at 5.8 MW, WH3 at 8.4 MW and WH4 at 20 MW), but only 24 MW of firm flows in winter in drought conditions, a loss of WH4 would only effectively reduce the available capacity by 4 MW (as the other three units would still be available), which is smaller than the loss of 15 MW via one of the units at Aishihik.

- For **Isolated Diesel Communities**, the criteria required each system to have installed generation capacity sufficient to meet 110% of the forecast peak load with the largest generation unit out of service.
- For the **WAF grid**, the required system generation capacity was determined as follows:
  1. The installed generation system, less a "Generation Reserve Requirement", must be able to meet the forecast WAF winter peak loads. For simplicity, this approach was used to define the Maximum Allowable Peak Load ("MAPL") for the WAF system at any time, i.e., the installed capacity at that time less the applicable Generation Reserve Requirement.

  2. The Generation Reserve Requirement was the reserve needed to meet forecast winter peak load with the loss of the single largest winter unit (one of the Aishihik units at 15 MW) plus the loss of 10% of the installed diesel capacity.

- For **individual communities on the WAF grid**, there was no generation capacity planning criteria in place. In practice, communities over about 300 people other than Faro and Whitehorse typically have local diesel generation installed to serve a dual purpose: overall grid support similar to major diesel installations at Whitehorse or Faro, as well as local supply during transmission outages. This applied at Ross River, Carmacks, Haines Junction, and Teslin, but has not been traditionally applied at Carcross. It was also not applied at smaller centres below 300 people.

  With respect to Faro, there has traditionally been a major diesel plant well in excess of the town requirements, but below the requirements of the Faro mine. Today, Faro maintains a diesel plant of 5.3 MW, which serves as a major diesel anchor point for the grid as well as for local supply in the case of transmission outages.

  For Whitehorse, there were no criteria regarding generation capacity requirements. In practice, however, Whitehorse has traditionally had sufficient generation (hydro plus diesel) installed in the local area to supply the community in the case of major transmission outages. This condition has now changed with recent growth in Whitehorse and the pending retirement of the Mirrlees units.

- For the **MD grid**, there was previously no approved capacity planning criteria. Previously, the Mayo system criteria had been based on supplying 110% of the peak load with the hydro units out of service. The separate Dawson system had been planned as an isolated diesel community (prior to the Mayo Dawson transmission development).

For both of the grid systems, the generation assets were included in the past capacity planning criteria calculation, but transmission assets were not considered. As a result, the possibility of transmission failure was not accounted for.

The MD Transmission Line was brought into service in 2002 to use surplus hydro at Mayo to offset diesel generation in Dawson City. The Dawson diesel plant is still in service in Dawson as back-up capacity well in excess of the community's peak loads (it had been installed to meet the Isolated system standard). There are also two diesel units in Mayo that together approximate the local Mayo firm peak loads. Consequently, the WAF grid was the focus during the examination of the capacity planning criteria.

Table 3.4 depicts the generating complement and Maximum Peak Load under the previous planning criteria for WAF. The result is that a WAF load of 68.7 MW can be allowed under these criteria without exceeding the calculated capability of the current generating units in service.

**Table 3.4:
Current WAF Generating Complement and
Maximum Allowable Peak Load (MAPL)
under Previous Planning Criteria**

Unit	Rating (MW)
Whitehorse Hydro (winter - for all units)	24.0
Whitehorse diesel #1	3.0
Whitehorse diesel #2	4.2
Whitehorse diesel #3	4.2
Whitehorse diesel #4	2.5
Whitehorse diesel #5	2.5
Whitehorse diesel #6	2.7
Whitehorse diesel #7	3.3
Faro diesel #3	1.0
Faro diesel #5	1.3
Faro diesel #7	3.0
Aishihik #1	15.0
Aishihik #2	15.0
Carmacks diesel (YECL)	1.3
Haines Junction diesel (YECL)	1.3
Teslin diesel (YECL)	1.3
Ross River diesel (YECL)	1.0
Fish Lake hydro (2 units - YECL)	0.4
Total	87.0
Less: 15 MW hydro Reserve	-15.0
Less: 10% Diesel Reserve	-3.3
Maximum Allowable Peak Load (MAPL)	68.7

3.3.3 Previous Yukon Criteria Compared with Criteria for Other Jurisdictions

Yukon Energy's previous capacity criteria do not identify any specific BES system capacity requirement that can be readily compared with criteria adopted in other jurisdictions for integrated systems. This was because the previous Yukon criteria only dealt with the concept of a "reserve" rather than actually assessing the likelihood (or probability) that the generation available will be insufficient to supply the load at any given point in time, which has been adopted by the majority of Canadian utilities. The previous Yukon criteria are described as "deterministic" in that a set test is adopted for each system as a proxy intended to ensure adequate capacity – however, to assess the adequacy of this proxy, it was necessary to compare Yukon's situation with criteria adopted in other jurisdictions.

Reliability experts were hired from the University of Saskatchewan in 2004 (under the direction of Dr. Roy Billinton) to study and determine the probabilities inherent in the existing Yukon capacity planning criteria. NWT Power Corporation has used Dr. Billinton as an advisor in the development of their Snare-Yellowknife system planning criteria, and received approval from its regulator for their revised criteria in November of 2004.

The review confirmed that a comparison of Yukon's previous criteria with criteria typically adopted by major Canadian utilities cannot be readily undertaken. However, in terms of the maximum peak load that can be supported, the review indicated that WAF generation was not adequate to supply the 68.7 MW peak (as would be allowed under the existing criteria (see Table 3.4)) within any reasonable reliability standard adopted elsewhere in Canada[4].

Generation Adequacy (capacity) criteria in Canada today are typically derived by looking at the probability of an outage occurring due to having inadequate generation installed. This "probabilistic" approach looks at the likelihood of different load levels over the year and the likelihood of this load not being met due to unplanned outages of generation units or (in some limited cases) transmission facilities. The resulting criteria are expressed for a system as LOLE (stated as average number of hours or days per year that the BES system would be inadequate due to unplanned events) and Loss of Energy Expectation (LOEE, stated in MWh/yr of energy desired by customers that would go unserved). The review indicated that criteria commonly used in the NWT and southern Canada are LOLE between about one and two hours per year. If applied to the Yukon system (including consideration of constraints posed by the reliability of the Aishihik transmission line), the review indicated that such standards would only allow a maximum peak on the current WAF system of about 60.1 MW to 62.9 MW (compared to 68.7 MW under the previous criteria).

The review also indicated several key findings with regard to the previous WAF criteria, as follows:

[4] The work by Drs. Billinton and Karki reflects an evaluation of the WAF system with some minor overall differences from the capacity values indicated in Table 3.4. For example, Drs. Billinton and Karki did not consider Fish Lake as a reliable supply resource (the load data available was net of Fish Lake outputs, so the resource was effectively already accounted for in the loads) and used a higher assumed Haines Junction diesel output of 1.7 MW. Subsequent investigations indicate this assumed capacity for Haines Junction was too high. The net result, however, of these variations is minimal on the overall conclusions of the report.

1. **The WAF Deterministic Criteria was adequate in 1996/97** – The previous WAF capacity criteria provided excellent capacity reliability for residential and commercial customers in 1996/97 when the Faro Mine was in operation, with an LOLE of 0.008 hrs/year (based on the Faro Mine being the first customer to be interrupted). The reliability for industrial customers was considerably less at that time at about 9.4 hours per year. However, even in the event of a major shortage of WAF generation, the mine would still have typically received substantial supply from the Faro diesel plant (13.6 MW at that time).

2. **The WAF Deterministic Criteria is not adequate today based on LOLE** – The previous WAF capacity criteria provide poor capacity reliability today with an LOLE of about 5.9 hrs/yr at the peak load level allowed by the past criteria. The LOLE is considerably higher than it was in 1996, and also well above the normal range of one to two hours per year adopted by other Canadian utilities. Since there are currently no major industrial customers on WAF, this assessment in effect addresses the current capacity reliability for residential and commercial customers on WAF.

3. **Aishihik transmission line is key capacity constraint** – The transmission line from Takhini to Aishihik (L171 line) accounts for about 80% of the total LOLE today for WAF, and is thus the key WAF capacity constraint. This transmission line connects 31.3 MW of capacity to the Whitehorse area (as well as loads at Haines Junction). Were it not for this exposure to transmission outages, the LOLE would drop from 5.9 to 1.2 hours per year. The effect of considering the transmission line reliability is a reduction of 8.0 MW of load carrying capability at the two hours per year LOLE level.

4. **Previous criteria not adequate to track impacts of WD retirements** – The previous capacity criteria did not keep pace from a reliability standpoint with the planned retirement of Whitehorse capacity (WD1, WD2 and WD3). This is because retirement of 4.2 MW of diesel units at Whitehorse only reduced the MAPL by 3.8 MW (due to the 10% diesel reserve). The recent review however indicated that load carrying capability at an LOLE of two hours per year reduced by at least 4.2 MW upon a retirement of a unit of this type (in some cases slightly more than 4.2 MW).

In addition to LOLE generation criteria, some utilities (including NWT Power Corporation for its Yellowknife grid) also adopt a further emergency standard to ensure each major BES system can meet its peak winter loads with loss of its largest single transmission component (called “N-1” criteria). The previous Yukon criteria do not address the N-1 emergency criteria for systems such as WAF because the transmission facility loss was not considered in the capacity planning criteria. The overall result was to potentially expose Whitehorse area customers in particular to loss of adequate generation if the Aishihik line suffers a sustained failure at the time of system peak. In practice, this risk exposure was not material so long as there was adequate generation (including diesel units) in the Whitehorse area to reliably supply this area's loads; however, this situation is changing through growth in Whitehorse area loads and pending retirement of diesel units at the Whitehorse Rapids Diesel plant.

3.3.4 New Criteria Adopted by Yukon Energy

The new capacity planning criteria now adopted by Yukon Energy are as follows:

1. **WAF and MD System-wide capacity planning criteria:** Each system (WAF and MD) should not exceed a LOLE of two hours per year. The two hour measure is the same as that adopted in NWT and is comparable to the lower end of standards commonly used in southern Canada (which are typically from one to two hours per year LOLE).

   Although determining the LOLE requires sophisticated computer modelling, in practice the LOLE approach can generally be applied on WAF by benchmarking the two hours per year LOLE to a WAF overall "load carrying capability" of 62.9 MW. In rough terms, this load carrying capability changes by about 1 MW for every MW of non-Aishihik line generation that is added or retired (e.g., a retirement of 4 MW from the Whitehorse diesel plant will reduce this load carrying capability by about 4 MW, vice versa for additions). The benchmarking is also based on a rough assumption that the load carrying capability would be increased by about 8.0 MW if the current Aishihik transmission line constraint was removed. This could be done by twinning the line (i.e., creating a second line to allow access to Aishihik generation resources in the event of failure of the existing line).

   For MD, this criteria is well exceeded today. MD is well below two hours/year LOLE and also satisfies an N-1 condition in all locations.

2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Yukon's grids are small and isolated from major power grids, with single transmission lines connecting generation to load centres. Consequently, it was also determined to be appropriate to incorporate a standard to address the potential for sustained emergency conditions. In order to be able to address major emergencies, each system (WAF and MD) should be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single

contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source. For the case of the WAF system, the largest possible loss would currently be the Aishihik line, which connects 31.3 MW of capacity (30 MW from Aishihik, and 1.3 MW of Haines Junction diesel).

This N-1 criteria on WAF equates to a current load carrying capability (non-industrial) of 55.7 MW (excluding Haines Junction load, as it would not need to be served from the Whitehorse end of the Aishihik transmission line in the event that transmission line is out of service).

3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more should be considered as a preferred location for new diesel units if that community does not already have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

For isolated diesel communities no change has been adopted for the capacity planning criteria. Accordingly, the previous criteria is maintained for isolated diesel systems of being able to meet 110% of the community peak with the largest unit out of service.

3.3.5 Rationale for Adopting a Two-Part Criteria on WAF and MD

The two-part capacity planning criteria adopted by Yukon Energy for the WAF and MD systems is essentially the same as the capacity criteria approved by the regulator for the Yellowknife system[5]. This approach ensures that two different concerns are addressed on an ongoing basis.

The LOLE criteria provide an overall system measure that assesses the normal balance of the system including industrial loads, and the probabilities of experiencing outages due to having inadequate generation (and transmission) installed on the system. For Yukon, a standard approximately comparable to that used in Yellowknife (at about the lower end of planning standards used in southern jurisdictions in Canada), was viewed as reasonable. The LOLE standard in effect indicates the probability that the installed BES resources will be inadequate to supply the load for the total load on the system (including

[5] The only exception is that the Yellowknife N-1 criteria (called "minimum diesel") is slightly more stringent, in that 105% of the forecast winter peak loads must be carried under the N-1 condition, not simply 100% of the forecast peak as adopted by Yukon Energy.

industrial). In effect, it measures the balance between generation and loads (under normal probabilities of each system generating and key transmission units failing) and indicates how likely or unlikely it is that the balance will be unable to be maintained. This part of the criteria ensures that system capacity is planned on an ongoing basis to meet standards adopted and approved for other similar utilities in Canada.

However, the severity of a potential outage for non-industrial customers is not accounted for in the LOLE model. For example, despite an LOLE of two hours per year, it is entirely possible to have sustained outages (due to generation and transmission inadequacy, primarily related to the Aishihik line which is the largest single system constraint) for much longer than this under extreme winter conditions.

An emergency criteria was determined to be a necessary complement, given the potential seriousness of a sustained outage of the critical component of the system in winter (e.g., the Yukon system peak occurs in the coldest months of winter, when there is the least amount of sunlight to effect repairs such as to transmission facilities). This is to address the “surviving the first failure” consideration noted above (the N-1 test). YEC is incorporating this second level of testing into its capacity planning along with the LOLE criteria already described. As an example, the current biggest single winter generator on the WAF system is a single Aishihik wheel at 15 MW but the current biggest single potential loss of supply would be 30 MW following a failure on the Aishihik transmission line[6].

The N-1 criteria will not be extended to major industrial customer loads who typically maintain sufficient on-site diesel for their own emergency purposes (these customers would be informed that they would not receive full supply should the Aishihik line be out-of-service during the coldest days of winter).

Yukon Energy considered the NWT approach of requiring the system to meet the N-1 condition to a full 105% of forecast peak loads (slightly more stringent than a strict N-1) as a “safety factor for load forecast error”[7]. Given a WAF peak in 2005 of about 55.4 MW (excluding Haines Junction, which is not part of the N-1 criteria as it is on the western end of the Aishihik transmission line), such a “reserve” on WAF would equate to 2.8 MW. As the load today on WAF is only forecast to grow by about 1 MW per year (about 1.85%) and diesel capacity can be added relatively quickly if new capacity is seen to be required from unusual load growth, such a reserve for load forecast error was not considered necessary.

[6] The WAF system would also lose access to the 1.3 MW of generation installed at Haines Junction, but would similarly lose the need to supply the Haines Junction load from remaining WAF capacity (Haines Junction would be supplied by its own diesels) so there would be no impact on WAF of this additional loss.
[7] NWT Public Utilities Board Decision 14-2004, page 25.

The N-1 criteria will effectively govern the need for WAF system capacity requirements in the near term. However, this may not always be the case. As an example, if the Aishihik line was to be twinned, the N-1 condition would then only exclude 15 MW (the second largest single contingency on the WAF system is a loss of one Aishihik turbine) and it is likely that the LOLE condition would then govern the need for WAF system capacity. In addition, the LOLE condition may drive the need for new generation in the event of large new industrial loads, although these loads will have no impact on the N-1 criteria. It is important to ensure that ongoing capacity planning therefore addresses both concerns identified in the adopted two-part criteria approach.

3.3.6 Implications of the Adopted Criteria

The net effect of the new criteria adopted by Yukon Energy is a 2005 WAF system condition that is basically at the limits for all retail/wholesale loads (with approximately 300 kW of surplus in 2005). In short, any further wholesale or retail growth on WAF will be required to be met with new generation, as well as all future WAF system diesel unit retirements (see *Table 3.5, WAF Peak and Capacity Surplus (Shortfall) as Whitehorse Diesels are Retired (MW)*).

New capacity requirements of 18.7 MW are forecast for WAF for 2012 based on the adopted N-1 criteria as compared with only 12.5 MW based on the adopted LOLE criteria of two hours per year. Consequently the N-1 criteria has governed assessment today of new WAF capacity requirements. In contrast, the previous WAF criteria would indicate that no new WAF capacity would be required until 2010, and by 2012 only 5.5 MW of new capacity would be needed. These forecasts are based on current estimates of system load growth, excluding new industrial loads.

In contrast, MD generation under the new criteria adopted by Yukon Energy is well in excess of required levels in the absence of new major industrial loads. The same criteria can be applied to the MD system as capacity constraints arise on that system. However, at this point in time it is clear that MD is well below two hours per year LOLE and satisfies an N-1 condition in all locations.

Table 3.5:
WAF Peak and Capacity Surplus (Shortfall)
as Whitehorse Diesels are Retired (MW)

Year	Retirements	Previous Criteria: Peak (WAF wide, including loads served by Fish Lake)	Previous Criteria: Load Carrying Capability	Previous Criteria: *Surplus/ (shortfall)*	LOLE Criteria: Peak (WAF wide, including loads served by Fish Lake)	LOLE Criteria: Load Carrying Capability 2 hours/ year LOLE	LOLE Criteria: *Surplus/ (shortfall)*	N- 1 Criteria: Peak excluding Haines Junction (assumed to be 1 MW)	N- 1 Criteria: N – 1 criteria load carrying capability	N- 1 Criteria: *Surplus/ (shortfall)*
2005		56.4	68.7	*12.3*	56.4	62.9	*6.5*	55.4	55.7	*0.3*
2006		57.4	68.7	*11.3*	57.4	62.9	*5.5*	56.4	55.7	*(0.7)*
2007	WD3	58.5	64.9	*6.4*	58.5	58.7	*0.2*	57.5	51.5	*(6.0)*
2008		59.6	64.9	*5.4*	59.6	58.7	*(0.9)*	58.6	51.5	*(7.1)*
2009	WD2	60.6	61.1	*0.5*	60.6	54.5	*(6.1)*	59.6	47.3	*(12.3)*
2010		61.7	61.1	*(0.6)*	61.7	54.5	*(7.2)*	60.7	47.3	*(13.4)*
2011	WD1	62.9	58.4	*(4.4)*	62.9	51.5	*(11.4)*	61.9	44.3	*(17.6)*
2012		64.0	58.4	*(5.5)*	64.0	51.5	*(12.5)*	63.0	44.3	*(18.7)*

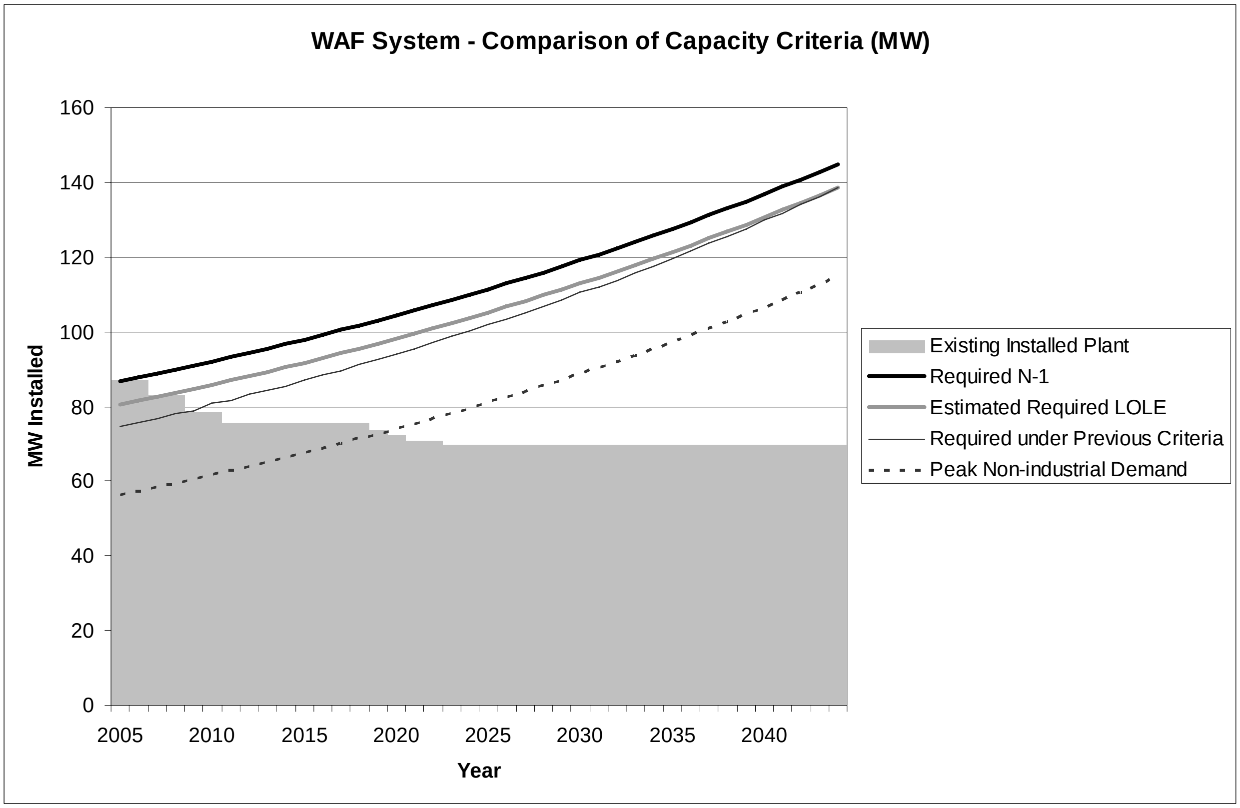
As long as the WAF system with the current Aishihik line (i.e., no twinning of this line) can meet the wholesale/retail peak under the N-1 criteria, up to 6-7 MW of major industrial loads can be served without driving new generation investment for capacity reasons.

Adoption of the revised planning criteria was required to plan and develop infrastructure in Yukon. The new criteria indicate a need to have WAF generation additions occurring in the next 12-24 months. This may drive a requirement for capital investment in excess of $3 million in the near-term.

Figure 3.1 WAF System – Comparison of Capacity Criteria depicts Yukon Energy's need for new capacity through to 2045 under the N-1, LOLE, and previous criteria. Forecast WAF peak load (non-industrial) is depicted by the dashed line. Required capacity is shown based on the forecast peak load and the three different capacity planning criteria examined in Table 3.5 – this analysis assumes continuation of the current WAF systems without any new investment (such as twinning of the Aishihik line) to remove of the current Aishihik transmission line constraint. Forecast existing installed plant reflects retirement assumptions as noted in Figure 3.1. In effect, the analysis assumes that all new capacity requirements are met with diesel installed at Whitehorse.

Of note is that even under the existing capacity planning criteria, the planned retirement of the Mirrlees combined with expected load growth over the next five to six years will require new capacity to be installed on the WAF system. However, with adoption of the new criteria noted above, this requirement will lead to the need for new capacity to address all planned Mirrlees retirements plus basically all load growth from 2005 forward.

Figure 3.1:
WAF System – Comparison of Capacity Criteria



3.4 SUMMARY: REVISED CAPACITY PLANNING CRITERIA

The following revised capacity planning criteria have been adopted by Yukon Energy:

1. **WAF and MD System-wide capacity planning criteria:** Each system (WAF and MD) will be planned not to exceed a Loss of Load Expectation (or LOLE) of two hours per year.

2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each grid system (WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source.

3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already

have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

For isolated diesel communities no change has been adopted for the capacity planning criteria (which requires being able to meet 110% of the community peak with the largest unit out of service).

4.0 NEAR TERM REQUIREMENTS

"Near term" requirements address Yukon Energy generation and transmission commitments required before 2009 for major investments with anticipated costs of $3 million or more. Given the time needed for possible construction, the assessment examines possible in-service needs to meet loads out to 2012.

This chapter focuses on opportunities for enhancements to existing hydro stations as well as cost-effective resource supply alternatives capable of meeting the 15 to 27 MW of new capacity required within the defined near term period. The sections for this chapter are as follows:

- Section 4.1: Planning Approach and Timeline
- Section 4.2: Requirements
- Section 4.3: Options
- Section 4.4: Assessment
- Section 4.5: Proposed Actions

4.1 PLANNING APPROACH AND TIMELINE

Potential major investments in the near term for new generation or transmission relate to opportunities to enhance existing system assets, and to address WAF system capacity shortfalls. As reviewed in Section 4.2, the WAF shortfalls are forecast to be between 15 and 27 MW within the next five to six years. In contrast, with material surplus hydro generation on both the WAF and MD systems, there is no apparent near term requirement or opportunity for major new energy-related investments. There is a near term opportunity to extend the WAF grid to supply two possible new mines in the Carmacks to Pelly Crossing region using available surplus hydro generation (see *Section 4.2: Requirements*).

Near term opportunities in respect of existing hydro assets focus on both the Whitehorse and Aishihik generating stations. In each case, the projects have been reviewed over many years in different variations. These projects fit with similar initiatives in other jurisdictions such as BC Hydro's "Resource Smart" program focusing on means to provide additional energy or capacity "through physical or operational modifications to existing facilities", and similar Supply Side Enhancement programs at Manitoba Hydro.

In respect of capacity requirements, as reviewed below capacity shortfalls on WAF under the new capacity planning criteria begin to arise as soon as 2006, even before any Whitehorse diesel units are retired, and become sufficiently material in 2007 to require overall spending commitments exceeding the

$3 million level. Consequently, planning activities for the near term focus on supply options that are sufficiently well-defined to make commitments and begin the necessary licencing or construction activities by, at the latest, late 2006 to early 2007.

The planning approach for near term requirements follows the general planning approach set out in Chapter 1:

1. **System capability** (part of Section 4.2: Requirements) over the intended "near term" horizon (in this case, as explained above, to about 2012) is reviewed, particularly noting planned retirement of generating capacity.
2. **System capacity requirements** (part of Section 4.2: Requirements) are reviewed over the near term based on the new capacity planning criteria, focused on non-industrial load forecasts plus potential loads from reasonably well-defined industrial load options that might emerge in the near term; sensitivities are examined with regard to different possible load forecasts.
3. **Forecast New Facilities Requirements** (part of Section 4.2: Requirements) are reviewed over the near term based on system capacity requirements, opportunities to enhance existing hydro generation facilities and, in the event loads are sufficiently high, opportunities to displace diesel-based energy production.
4. **Resource Options** (Section 4.3: Options) are reviewed over the near term, focused on potential resources of sufficient definition, size and timing for in-service to meet the near term requirements for new facilities.
5. **Assessment of Resource Options** (Section 4.4: Assessment) are reviewed over the near term, focused on technical feasibility (including timing), cost efficiency, reliability, and risk (in particular, risks related to "markets" or future loads developing differently than indicated by forecasts today).

Key considerations with respect to system capability are reviewed in Chapter 3. Over the focused near term to about 2012, one key system capability issue relates in large part to the planned retirement of the three Mirrlees engines:

- **WD1:** A Mirrlees KV12, installed in 1968, currently rated at 3.0 MW MCR (nameplate 3.92 MW) with a planned retirement in 2011;
- **WD2:** A Mirrlees KV16 from 1968, currently rated at 4.2 MW MCR (nameplate 5.15 MW), with a planned retirement in 2009; and,
- **WD3:** A similar Mirrlees KV16 dating from 1970, currently rated at 4.2 MW MCR (nameplate 5.15 MW) with a planned retirement in 2007.

The three Mirrlees engines have been planned for retirement for many years, including as far back as the 1992 Resource Plan hearing (when they were planned to be retired in 1998, 1998 and 2000 respectively). By 1996, the planned retirement of these units had been extended by four years to reflect in part lower running hours during the 1993-1995 closure of the Faro mine, as well as maintaining their running hours at a very low level by maintaining the units at the bottom of the stacking order.

With the 1998 closure of the Faro mine, Yukon Energy was able to further extend the planned retirements to the current schedule (WD1 by 9 years, WD2 by 5 years and WD3 by 3 years) based on updated assessment of the relative condition of each unit, and continued minimal operation.

However, at the present time, it is clear that further delay of retirement of these units is not possible without material investment in major tear-down overhaul work. This is further confirmed by the BC Hydro Condition Assessment (see Section 2.1) which concluded that these units were at “end-of-life”. In addition, the Mirrlees are low-speed base load units (514 RPM) which are poorly suited to the current operating regime of stop-and-start operation. Finally, Yukon Energy and others who maintain Mirrlees engines of this vintage (including Northwest Territories Power Corporation) have substantial concern with the ongoing ability of the current owner of Mirrlees to provide ongoing parts and technical support.

Any further delay in planning for an orderly retirement or, if possible, major refurbishment of the Mirrlees units will in all likelihood substantially increase the risks of a major failure or inability of these units to supply reliable utility standard service when required.

4.2 REQUIREMENTS

Yukon requirements for new capacity or energy resources in the near term result from the combined effects of three factors within each system:

- forecast non-industrial load growth, particularly on WAF related most notably to growth in the Whitehorse area;
- potential opportunities to connect new major industrial mine loads, including via new transmission to supply potential mines in the Carmacks to Stewart Crossing area; and,
- changes in the capability of existing generation or transmission resources, including changes related to new capacity planning criteria and planned retirements.

As set out in detail in Section 4.3, there are only two material new near term resource supply opportunities and/or requirements on Yukon systems:

1. New firm WAF capacity required, due to WAF winter peak capacity exceeding the maximum loads allowed on the system under new capacity criteria (however, this system has no need for new firm energy capability due to ongoing surplus hydro energy generation of over 90 GW.h/yr, with about 21 GW.h/yr of this surplus being currently used to supply interruptible secondary sales).
2. Opportunities to enhance existing WAF hydro generating assets to increase energy and/or capacity outputs.

The MD system has surplus hydro energy generation of about 17 GW.h per year, and surplus winter peak capacity with existing hydro and diesel generation. Consequently, as reviewed in Section 3.3, the LOLE for the MD system is not likely to exceed 2.0 hrs per year for many years into the future, absent major new industrial loads on this system. The MD system also satisfies the N-1 capacity criteria at each end of the MD transmission line as well as at the community of Stewart Crossing.

With respect to WAF requirements, four near term load cases have been identified, and are set out in the following sections. Each section includes graphs depicting the capacity and energy requirements under each scenario as follows:

- **Forecast WAF generation capacity:** The MW capacity requirement at winter peak is indicated, showing separately the capacity to meet N-1 Requirement and the LOLE Requirement, as well as the projected winter peak generation load. The graphs also illustrate the capability to meet this requirement from existing capacity, net of scheduled retirements, and the forecast need for new required capacity. For the purposes of illustrating requirements, the new capacity is portrayed in these "requirements" graphs based on a consistent assumption that requirements will be met by new 4 MW diesel units.
- **Forecast WAF generation energy:** The MW.h per year from existing hydro and from diesel are indicated separately. The energy graphs also show any surplus supplied as Secondary interruptible energy up to the forecast maximum Secondary Load expected (maximum of 30 GW.h per year). The forecasts show the generation expected to occur, and therefore these graphs do not show the full surplus hydro energy generation capability (which in many cases materially exceeds forecast Secondary sales).

4.2.1 Basis for Non-Industrial Load Forecasts

Yukon Energy's near term non-industrial load forecasts for WAF are shown in Table 4.1, and are reviewed in more detail below.

Table 4.1:
Near Term Non-Industrial Load Forecasts

Load Forecasts				
Population Increase	**Source**	**Increase in Use/Customer**	**Combined Percentage Increase**	**Sensitivity**
0.4%	Yukon Bureau of Statistics: Medium Growth Projection	0.5%	0.9%	Low
1.0%	City of Whitehorse Population Increase (4 year average)	0.5%	1.5%	Medium-Low
	Mid-point		1.85%	Medium
	Yukon Energy's 3-Year Average Recorded Increase in Consumption		2.2%	Medium-High
	Yukon Energy's Highest Annual Recorded Increase in Consumption		3.0%	High

Yukon Energy’s long-term non-industrial load forecast is based on a review of sales over past periods (as far back as 1992 in some cases, but focused on the period since 1998 when the Faro mine last closed), readily available information on the Yukon economy and other relevant statistics, and in some cases review of load forecasting variables used by other Canadian utilities.

The Yukon landscape is such that forecasting long-term non-industrial loads with precision is considerably more difficult than in southern jurisdictions. Although electricity consumption in many cases follows trends typical of other places in Canada, the Yukon economy can be substantively impacted by single events that, in most cases, cannot be foreseen with any accuracy more than a very short period in advance of the event (this short period can be one to two years or less). Examples include the opening and closing of large resource projects, such as mines, and major changes to Government of Canada funding to the Yukon Government.

Since the 1992 Resource Plan, the most material change in the Yukon electricity load forecast landscape has been the closure of the Faro mine (previously 40% of Yukon’s load). Not only did the closure reduce 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 also major centers such as Whitehorse (Yukon Energy wholesales to YECL declined from 232 GW.h in 1996 to 217 GW.h in 2001).

The 1998 Faro mine closure impacts appear to have been largely incorporated into the Yukon economy and population by 2001. During this 1998-2001 period, out-migration of about 10% of the Yukon's population occurred (over 3,000 people).

Since 2001, the Yukon's economy and electricity loads have begun to develop a more normalized pattern. This is most evident in YECL's native load (Yukon Energy's wholesales to YECL plus YECL's own WAF Fish Lake generation added back) which has been characterized by growth of about 2.2% per year (three year average from 2001-2004) with one year growth as high as 3% in 2004. As a normal level of growth in the major load centers in Yukon, this three year average growth rate is likely within a reasonable range of forecasts for the near term period in question. This reflects three factors:

1. **Population growth:** Population in the major load center of Whitehorse has been recently increasing by approximately 1% per year reflecting fertility and mortality rates, net in-migration to Yukon and net in-migration to Whitehorse from other places in Yukon (both of these net in-migration trends have been positive since 2001). From 2001 to 2004 the resulting Whitehorse growth rate was in excess of 1% per year. Growth in customer numbers is expected to be at about this same level if not slightly higher due to reduced average number of persons per household, reflecting normal Canadian trends.
2. **Use per residential customer:** Use per customer for residential customers is assumed to be increasing at about 0.5% per year. Changes in use per customer are typically small over time, with Canadian utilities typically forecasting similar uptrends over the next 20 years for non-heating loads. This uptrend reflects in part increased use of certain appliances (such as internet connected computers and other electronic devices) offset by modest efficiency improvements in certain appliance sectors (for example, fridges are now far more efficient than in past years, but the stock of fridges typically changes quite slowly so is only a modest incremental change each year).
3. **Use per commercial customer:** Use per customer for commercial customers is not expected to vary materially from trends seen for residential customers, although growth may be slightly higher reflecting the trend towards larger stores and facilities (such as the Argus properties).

Based on the above assessment, Yukon Energy has based long-term load forecasts on a **base case** of 1.5% (medium-low) to 2.2% (medium-high) growth per year with 1.85% growth per year as the mid-point. In order to ensure the impacts of potential extreme outcomes with respect to non-industrial loads are considered, load forecast uncertainty to a range of 3.0% annual growth (High Sensitivity) and 0.9%

annual growth (Low Sensitivity) have been considered where these extremes have the potential to materially change the recommendations for major new investments in power resources.

- The **high sensitivity** of 3.0% per year is based on the highest one year wholesale sales growth rate experienced by YEC (2004). This was a period of very high growth, but given that it is the very recent experience, it is necessary to consider the potential that this rate is representative of a major new evolution with respect to Yukon electrical load.
- The **low sensitivity** of 0.9% per year based on a very nominal growth which is the combination of strictly the growth in use per customer plus the Yukon Bureau of Statistics population forecast growth assuming no in-migration (0.4%). This is consistent with the Yukon experience of not having had any periods of sustained zero to negative growth in the non-industrial system (and reflecting the fact that today's loads are not predicated on any downside risks related to underlying industrial projects, as no major industrial customers are currently receiving service in Yukon).

4.2.2 Basis for Near Term Industrial Load Forecasts

In order to address the current expectation that two new industrial loads may proceed in the area north of Carmacks, two industrial load cases have been included in the near term analysis (a range of other still more optimistic industrial development scenarios are examined separately in Chapter 5):

1. **No new industrial load**, and
2. **Industrial loads consistent with Minto and Carmacks Copper both being developed in the near term,** or about 9-11 MW of new load (2-4 MW for Minto plus 7 MW for Carmacks Copper) and 64 GW.h of annual energy. These mine projects are not expected to be long-lived, at 12 years for Minto starting 2007 and 8.5 years for Carmacks Copper starting 2008 (although these starting dates may be delayed by other processes and development timelines).

4.2.3 Near Term WAF Load – Cases Analyzed Based on Non-Industrial and Industrial Requirements

Based on the above near term non-industrial and industrial load forecasts, four near term WAF load cases have been considered:

1. **Base Case:** The Base Case near term assumptions are based on non-industrial loads at the mid-point base case level (1.85% per year) and no new industrial loads.
2. **Low Sensitivity Case:** This case maintains non-industrial loads at the low sensitivity level (0.9% growth) and no new industrial loads.

3. **Base Case including Mines:** This case combines the Base Case assumption for non-industrial (1.85% growth) plus near term development of the Minto and Carmacks Copper loads at a combined 9 MW.
4. **High Sensitivity Case, including Mines:** As the largest near term growth scenario, this case combines the high sensitivity non-industrial load growth (3.0%) with near term development of the Minto and Carmacks Copper loads.

4.2.4 Base Case Requirements

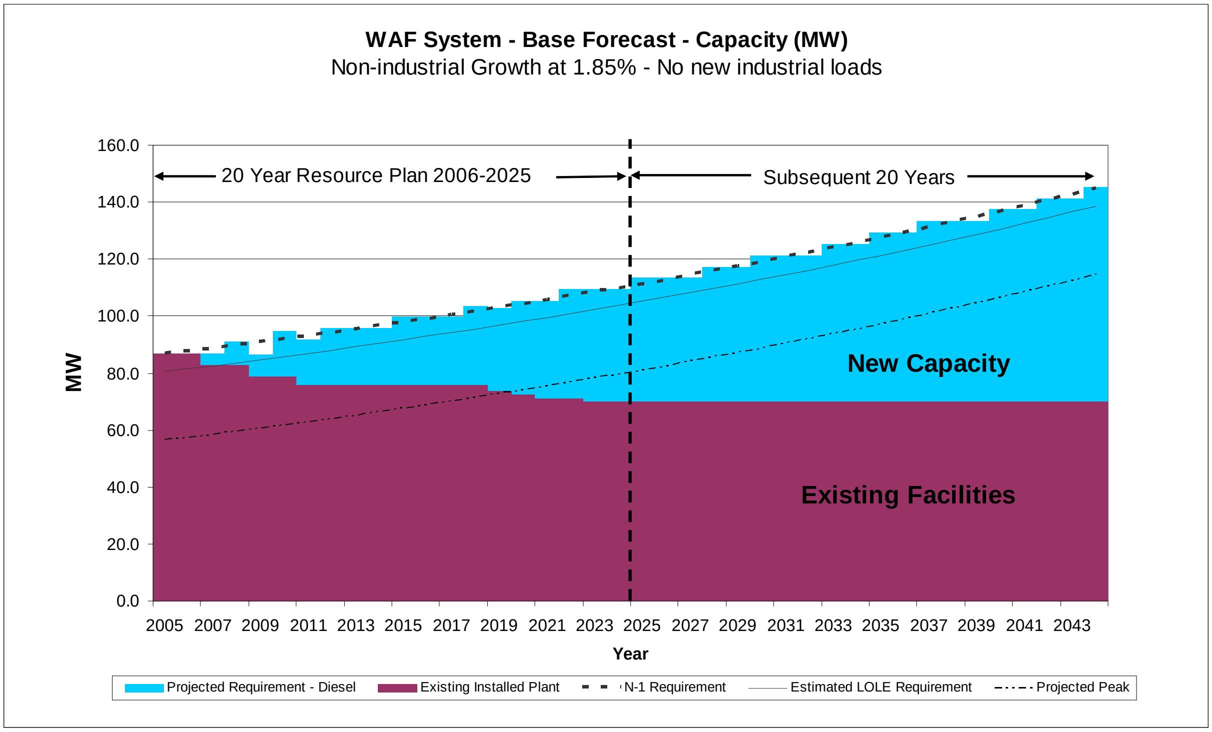
Under the Base Case, forecast loads exclude any major industrial customers. Non-industrial load growth is projected at 1.85% per year.

Capacity: Under the Base Case, there is a 0.7 MW capacity shortfall forecast for 2006, increasing to 18.7 MW by 2012 assuming that all three Mirrlees units (11.4 MW) have been retired by that time[1].

Figure 4.1 provides a 40 year horizon (20 years of Resource Plan plus the 20 subsequent years) and indicates the capability of the existing facilities with planned retirements as well as the requirement for new facilities to meet the proposed new planning criteria (LOLE and N-1, indicated by solid and dotted lines respectively). In this figure, five new 4 MW diesel generation units (or equivalent 20 MW) are assumed to be installed to meet the capacity shortfalls to 2012.

[1] Note that under the previous capacity criteria, the capacity shortfall in 2012 is 5.5 MW as noted in Section 3.3, and is entirely driven by the retirement of the 11.4 MW of current Mirrlees capacity.

Figure 4.1:
WAF Base Case Capacity Requirements

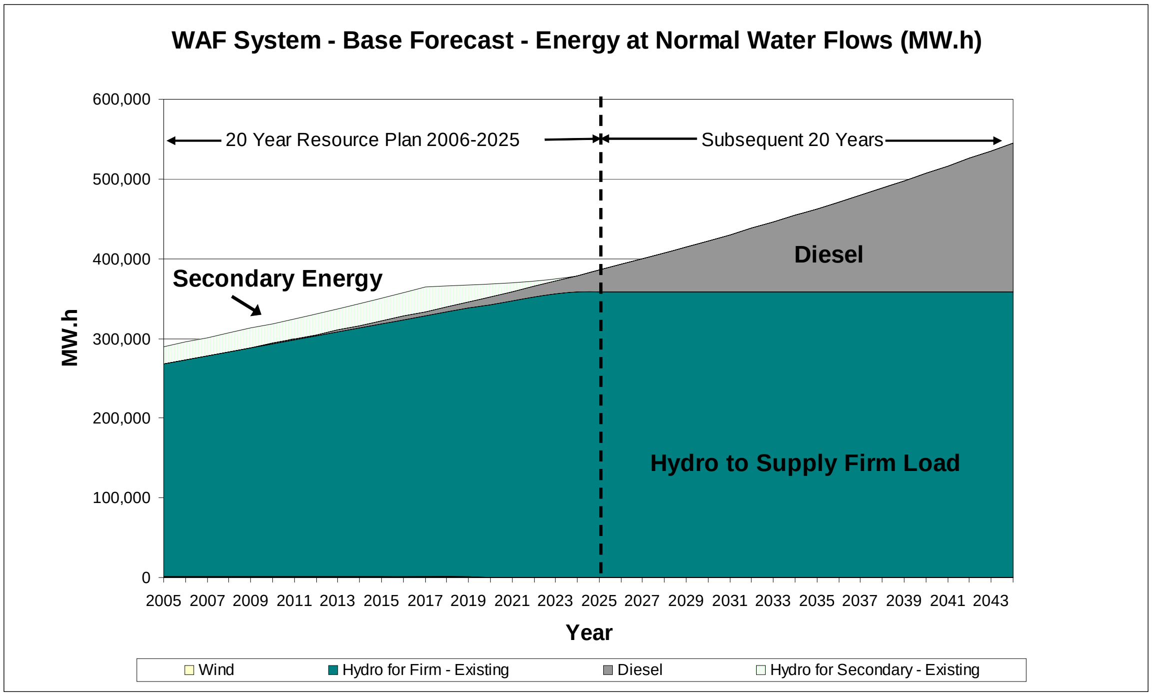


Energy: The Base Case analysis as reviewed in Figure 4.2 indicates that diesel generation is not required to supply sustained loads (e.g., loads in excess of average annual hydro energy generation) until at earliest the end of the 20 year forecast planning period. Some diesel generation is required for peaking purposes (i.e., brief time periods during the winter peak months), but these peaking diesel generation requirements remain below 10 GW.h per year until after 2020 (i.e., near the end of the 20-year planning period), increasing to about 28 GW.h/year in 2025. Figure 4.2 also indicates the potential energy available for supplying secondary power up to the expected maximum annual program subscription of 30 GW.h/year[2].

In summary, there is no opportunity under the Base Case near term forecast to develop new non-diesel generation to displace diesel fuel until near the end of the 20 year planning horizon.

[2] The analysis does not attempt to determine the secondary energy demanded that would go unserved due to short-term winter interruptions during periods of peaking diesel, i.e., the analysis determines only the annual impacts on energy available to service secondary loads. In reality, actual secondary sales would experience greater short term interruption as load growth increases the periods of peaking diesel operation during each year.

Figure 4.2:
WAF Base Case System Energy Requirements

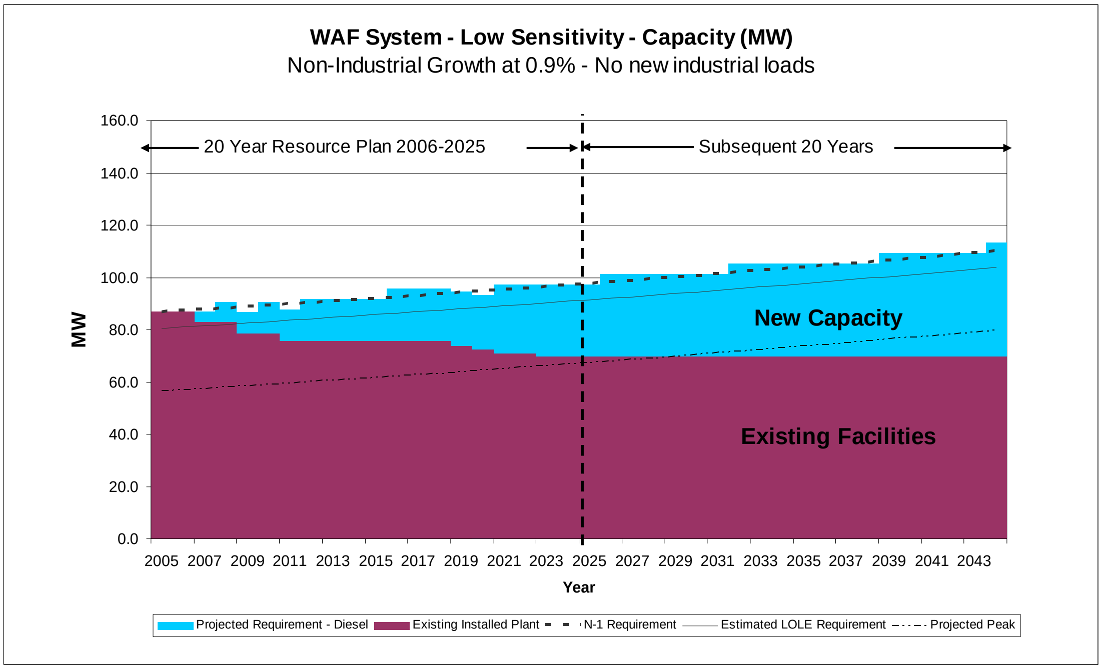


4.2.5 Low Sensitivity Case

The Low Sensitivity Case is based on non-industrial load growing at 0.9%/year and no new industrial loads.

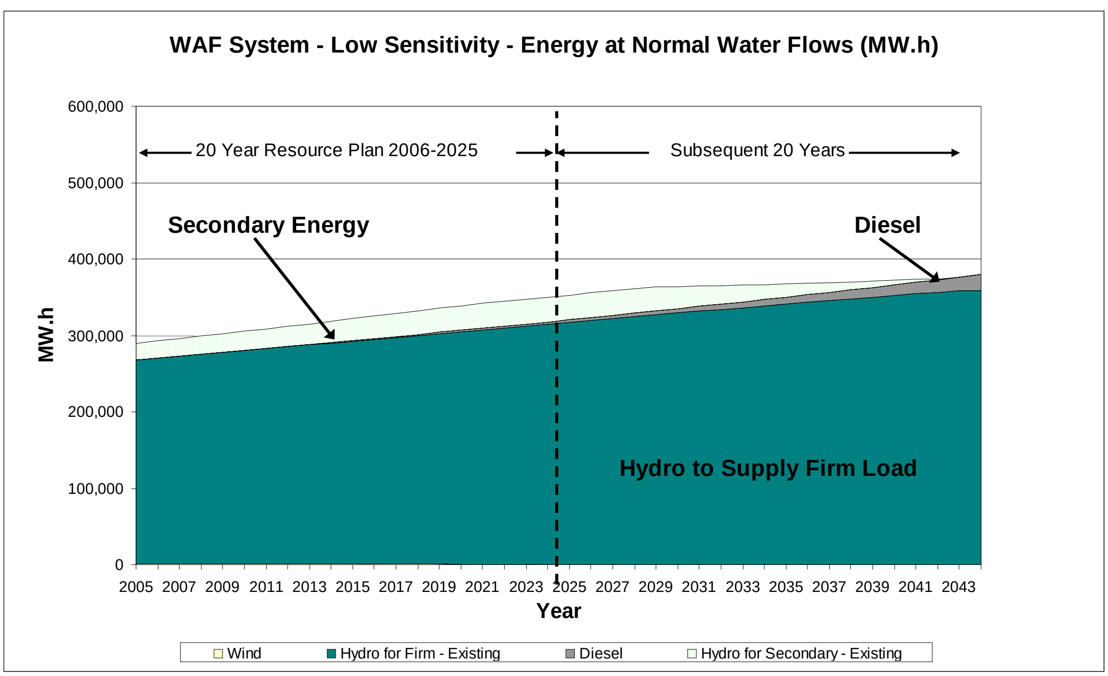
Capacity: Under this case, as reviewed in Figure 4.3, capacity shortfalls occur in 2006 of 0.2 MW with growing requirements thereafter driven primarily by retirement of diesel units (11.4 MW of retirements by 2011). The Low Sensitivity Case forecast indicates 14.7 MW of capacity shortfall by 2012. Figure 4.3 identifies a requirement by 2012 of four new 4 MW diesel units (16 MW).

Figure 4.3:
WAF Low Sensitivity Case Capacity Requirements



Energy: Under the Low Sensitivity Case (see Figure 4.4), as with the Base Case, there is no requirement for material diesel generation in the 20 year planning horizon.

Figure 4.4:
WAF Low Sensitivity Energy Requirements

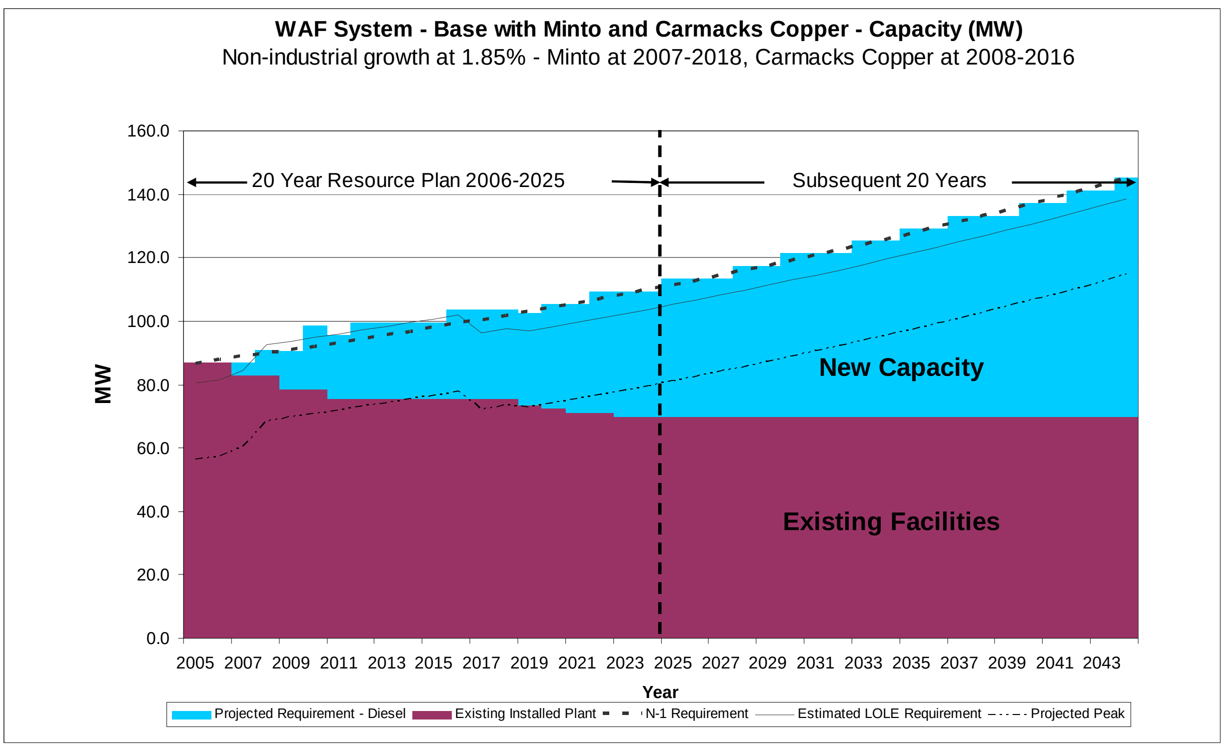


4.2.6 Base Case with Mine Loads

The Base Case with Minto and Carmacks Copper Mine loads includes the same non-industrial load growth of 1.85% from the Base Case, plus an assumed near term connection of the Minto and Carmacks Copper new mine loads to the WAF grid. This case presumes near term development of new transmission from Carmacks to at least about Pelly Crossing with spurs to connect these two new mines.

Capacity: Under this case, capacity shortfalls of 0.7 MW arise in 2006, growing to 21.5 MW by 2012 (in this case driven by the LOLE criteria instead of the N-1 criteria which drove capacity shortfalls for the Base and Low sensitivity cases)[3]. The capacity shortfall is illustrated in Figure 4.5 below as six new 4 MW diesel units (24 MW) assumed by 2012.

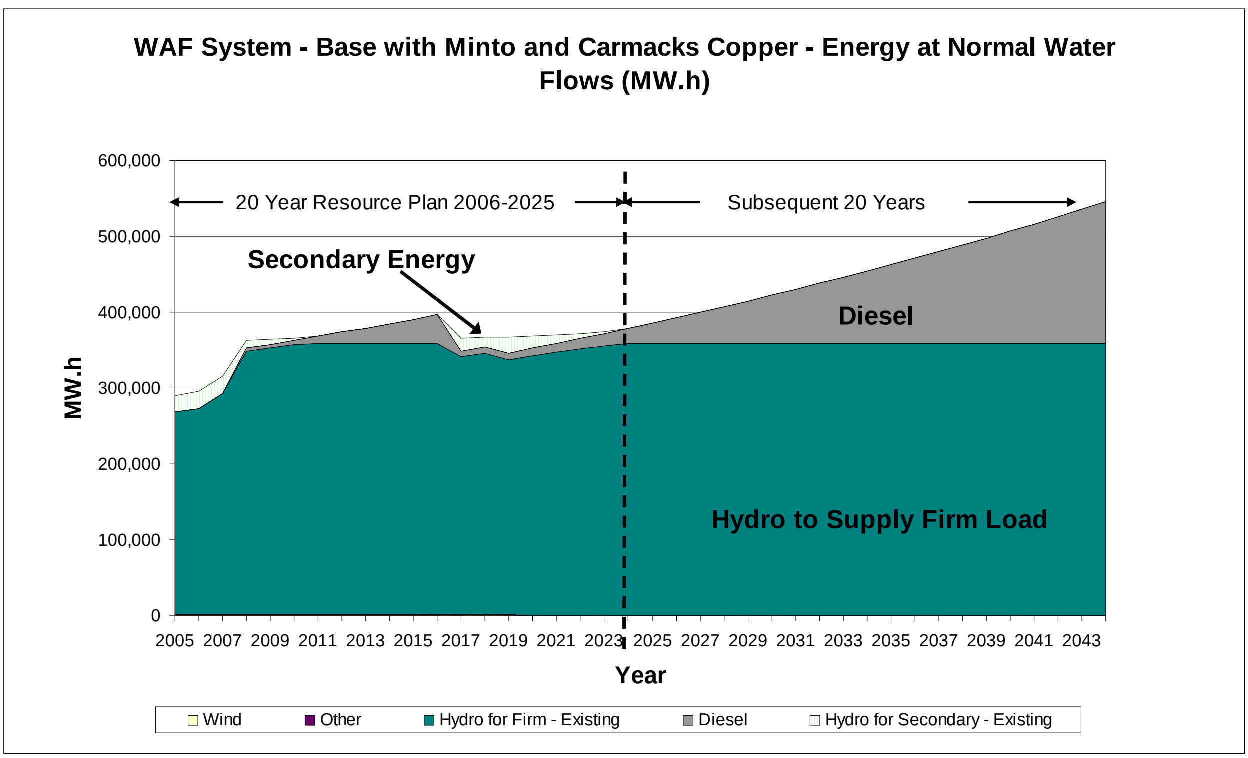
Figure 4.5:
WAF Base Case with Mine Capacity Requirements



[3] The combined mine loads in this scenario total 9 MW. Mine loads do not contribute towards peak loads for N-1 calculations but do contribute for LOLE (see Section 3.3). Under Base Case load scenarios, N-1 is requiring additions of capacity approximately 6.2 MW ahead of LOLE requirements. For this reason, the first 6.2 MW of industrial load do not drive any additional capacity requirements over and above the basic base load requirements. The result in this case with the added 9 MW of industrial load is an increase in capacity required compared to the Base Case (in order to serve the two mines) of only 2.8 MW (9 MW total load less 6.2 MW that can be served without additional capacity).

Energy: Under this scenario, as reviewed in Figure 4.6, the incremental mine load consumes largely hydro energy that would otherwise be surplus under the Base Case. However, with ongoing non-industrial load growth during the life of the mines, the WAF system begins to utilize diesel of up to about 40 GW.h per year for modest base load generation (reflects WAF system hydro capability of about 358 GW.h in a normal water year, with system energy requirements approaching 400 GW.h in about 2016 at the highest levels before mine closure). After the mine closures as assumed in this case, however, there would be a period of about seven years when excess hydro would return to the WAF system (along with the opportunity to make secondary sales) before normal non-industrial load growth would eliminate the hydro surplus (in 2024) and begin to drive new base load diesel requirements (beyond the current 20 year Resource Planning horizon). Although this load pattern may give rise to the opportunity to consider very small hydro or other low variable cost generation within the 20 year horizon (perhaps up to a 2-3 MW), the scale of any such generation would not materially affect the large capacity requirements (21.5 MW) beginning in the very near term.

Figure 4.6:
WAF Base Case with Mine Energy Requirements

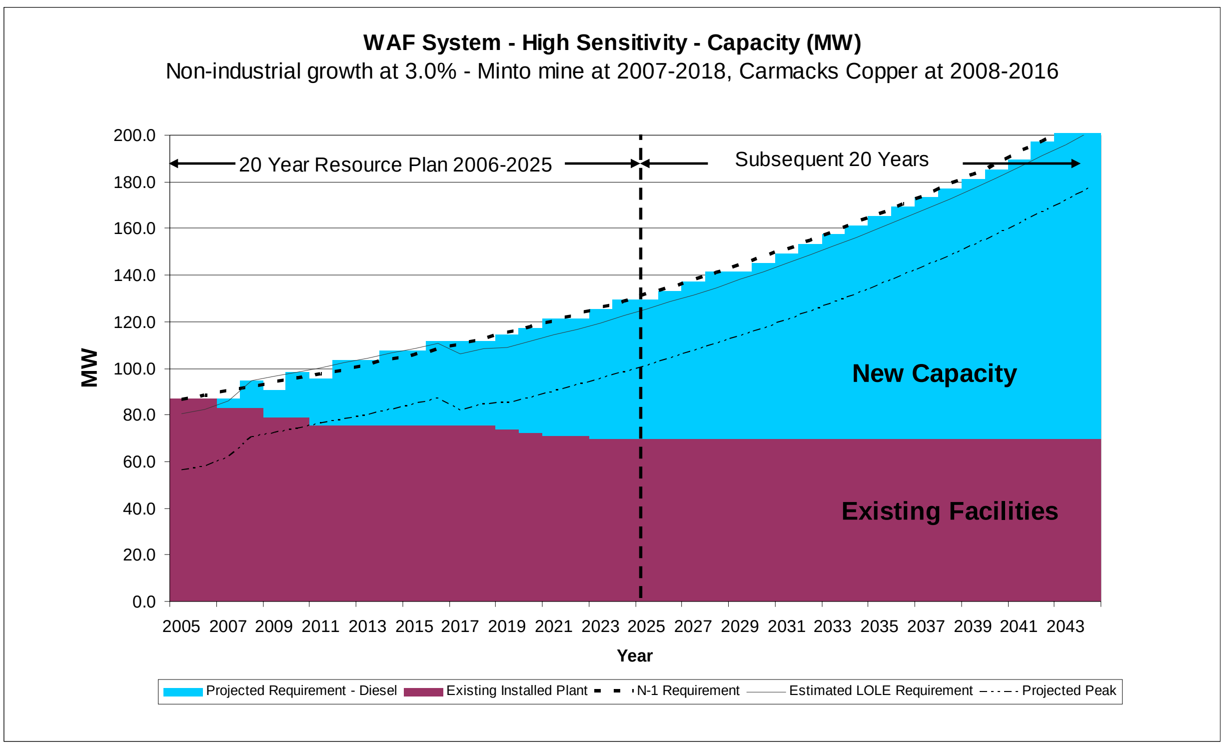


4.2.7 High Sensitivity Case Including Mines

In the High Sensitivity Case, the non-industrial load growth is forecast at 3.0% per year plus near term addition of the Minto and Carmacks Copper mine loads (which presumes near term development of new transmission from Carmacks to at least about Pelly Crossing with spurs to connect these two mines).

Capacity: Under this case, as reviewed in Figure 4.7, there would be material increases in the required installed capacity to meet the loads, assuming that the new capacity criteria are adopted. Capacity shortfalls in 2006 are at 1.4 MW, and by 2012 are at 26.7 MW (indicating the need in Figure 4.7 for an assumed seven new 4 MW diesel units, or 28 MW)[4].

Figure 4.7:
WAF High Sensitivity Case with Mines Capacity Requirements

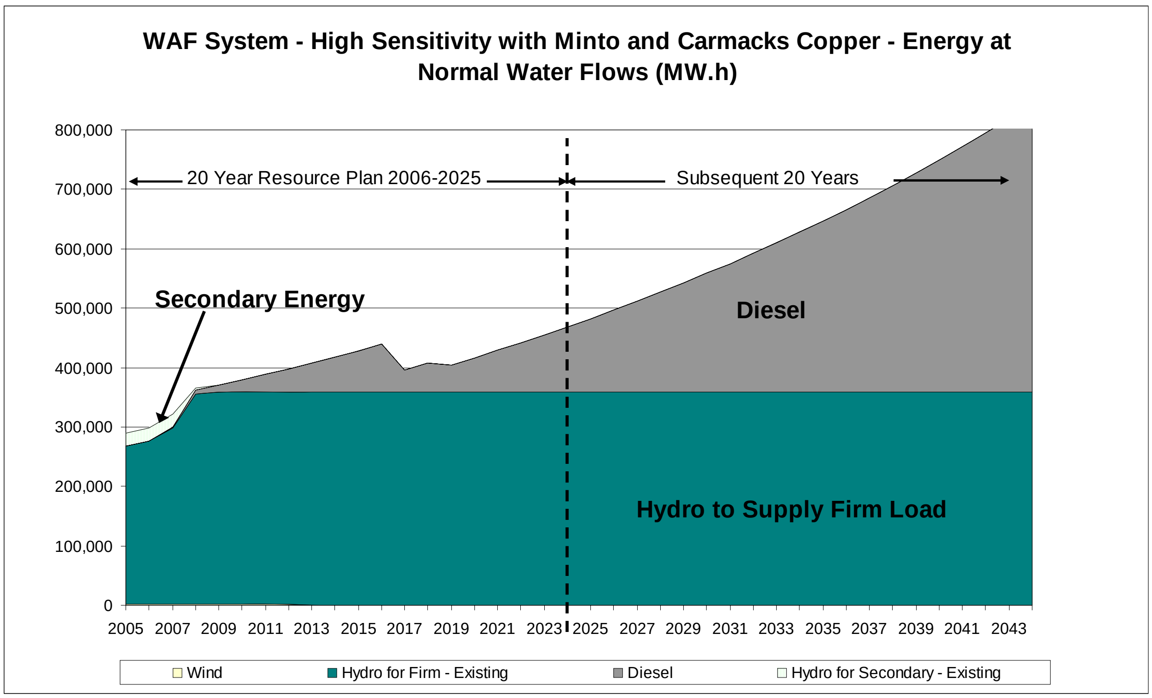


Energy: If the WAF system were to experience material sustained ongoing growth at the 3% level year over year, as well as the near term opening of both the Minto and Carmacks Copper mines as assumed in this high sensitivity case, the system will begin to experience base load diesel generation needs beginning

[4] Without the two mines, the High Sensitivity Case capacity shortfall in 2012 is 24.1 MW.

in 2009[5]. This may present near term opportunities to examine new non-diesel (e.g., hydro) generation. However, on a sustained long-term basis as reviewed in Figure 4.8, the requirement for new generation such as hydro after the mines close as assumed in this case is only in the range of about 50 GW.h per year (due largely to load reductions upon the closure of the mines)[6]. This scale of generation is consistent with hydro sites of about 8 MW. Consequently, even if new baseload energy projects are enabled by this major load growth, they will not be of sufficient size to address the very material (27 MW) new capacity requirements indicated under this scenario by 2012.

Figure 4.8:
WAF High Sensitivity Case with Mines Energy Requirements



Yukon Energy will also not likely be able to provide commitments to develop such capital intensive energy projects within the near term timeframes where capacity shortfalls begin to arise on the WAF system. This is because it would take a number of years to see loads develop at this high annual growth rate, as well as greater certainty with respect to mine loads, before capital intensive projects of this type would be suitable to consider. In addition, following appropriate commitments, hydro projects also typically require several years to plan, licence, design and construct.

[5] Without the two mines, the High Sensitivity Case will begin to experience base load diesel generation only in 2017 (when no surplus hydro for secondary sales).
[6] If 3% per year growth in non-industrial loads is sustained, as assumed in this case, diesel energy requirements grow to 124 GW.h by 2025.

4.3 OPTIONS

Based on the above requirements, three broad categories of project resource options are noted for the period prior to 2012:

1. **Opportunities projects to enhance existing facility energy and/or capacity output** or to allow better use of existing capabilities to ensure Yukon Energy has maximized the potential from past investments in major generating facilities. There are three well-defined near term project options in this regard:
   a) **Aishihik 3rd Turbine project:** Facility enhancements at Aishihik via a third turbine of 7 MW costing over $3 million to allow better ability to use the existing plant to meet peak loads, as well as more efficient use of water when operating at low outputs.
   b) **Marsh Lake Fall/Winter Storage project**: Improved water management at Whitehorse via changes to the water licence for upstream storage not costing over $3 million, in order to allow reduced discharge of water during the fall months to enhance the ability to store water for winter.
   c) **Carmacks to Stewart Transmission project**: The opportunity to use Government of Yukon infrastructure funding to develop new transmission costing over $3 million to interconnect the WAF and MD systems, including opportunities to connect to the WAF two potential new mines north of Carmacks.

2. **Major capacity-related replacement and/or expansion projects** costing $3 million or more to address substantial impending and unavoidable capacity shortfalls on WAF (approaching 15 MW to 27 MW by 2012) requiring new generation and/or transmission to ensure sufficient firm capacity to supply forecast peak loads. As noted in Section 3.3, this shortfall is driven in large part by exposure to Aishihik transmission line outages. Two main concepts are explored in this regard:
   a) **Maintain/Replace/Expand Whitehorse Diesel projects:** One concept seeks to reduce exposure to the transmission line weaknesses through reducing the potential *impact* of transmission line outages, focused on maintaining existing diesel (a major Life Extension project on the Mirrlees units), or installing new diesel generation on the WAF grid not dependent on the Aishihik transmission line (a major Whitehorse Diesel Replacement and Expansion project).
   b) **Aishihik 2nd Transmission Line project**: Alternatively, the Aishihik 2nd Transmission Line Project concept seeks to reduce exposure to weaknesses through reducing the potential *incidence and duration* of transmission line outages through developing redundancy in the Aishihik transmission connection.

3. **Smaller supplemental projects** that may contribute towards meeting WAF supply requirements, but are either not currently defined or not currently expected to cost at least $3 million, and do not independently offer sufficient capacity to play a major role in satisfying the near term capacity shortfall requirements. Yukon Energy continues to evaluate supplemental projects in the near term and on an ongoing basis, but the main near term focus is on system enhancement opportunities and major replacement and/or expansion projects that will be required based on the new capacity planning criteria.

Studies are ongoing with regard to each of the above major near term options. The Submission provides a screening of projects based on current information (as summarized below), setting out the conditions and requirements relevant to proceeding with each specific option as well as initial cost estimates currently available for each option (which, aside from opportunity projects, remain preliminary and subject to ongoing adjustment and refinement). Updates will be provided during the review of the Submission to the extent that relevant new information is forthcoming for the ongoing studies of these projects.

4.3.1 Overview of “Opportunity” Project Options

The implementation of supply side enhancement or Resource Smart projects reflects a sensible and prudent approach to maximizing the value of existing resources. Such projects are routine in other jurisdictions in Canada, and often offer the lowest cost sources of supply available (although the scale can be modest in some cases).

Opportunities to put in place enhanced system assets can also be enabled by new loads or external funding to offset capital costs so as to put no burden on ratepayers.

Yukon Energy has focused on three major opportunity projects in the near term:

- **Aishihik 3rd Turbine Project (7 MW; 5.4 GW.h/year):** Up to 7 MW of capacity could be added to the existing Aishihik hydro plant through addition of a third turbine. This potential project was reviewed in the 1992 Resource Plan hearing as a potential 5 MW unit, and pursuant to YUB recommendations from that proceeding[7], Yukon Energy pursued and received environmental approvals for the unit in the new Aishihik Water Licence of up to 7 MW. The third turbine would yield an increase in long-term average hydro energy supply from Aishihik of up to 5.4 GW.h/yr (if load conditions on the system are sufficiently high) but

[7] The YUB recommended that Yukon Energy pursue a licence for “the maximum capacity that is economically, technically and environmentally feasible”.

in certain conditions prior to high WAF load conditions can allow displacement of diesel generation in excess of this level due to the ability to allow added Aishihik generation at the time of system winter peak (see Section 4.3.8). The 3rd turbine by itself is of no reliable peak capacity value whatsoever under the N-1 criteria as it is subject to the same Aishihik transmission line constraints as the existing units (unless an Aishihik 2nd Transmission Line project is in-service) and is similarly of limited reliable peak capacity value (0.6 MW) under LOLE criteria. Current investigations are updating capital costs and planning for this project.

- **Marsh Lake Fall/Winter Storage Project (about 1.6 MW; 7.7 GW.h/year):** There is the potential with a Marsh Lake Fall/Winter Storage project to increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and to increase its long-term average hydro energy by about 7.7 GW.h/yr (actual enhancement depends on load conditions assumed). The project involves seeking changes to the Whitehorse Rapids water licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period (during flood years, no change would be made during August and September, until after flood levels subside). In all cases, the water levels would remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake). Basically no new physical works are expected to be required for this project[8].

- **Carmacks-Stewart Transmission Line Project (about 6 MW; 15 GW.h/year, decreasing with time as MD load grows, plus opportunity to connect up to 2 new mines):** Yukon Energy is currently using Yukon Government Infrastructure Funding to carry out initial planning and permitting for this project; development of this project at this time is contingent on commitment of the necessary Yukon Government Infrastructure Funding as needed to ensure no adverse impacts on Yukon ratepayers. The development from Carmacks to at least Pelly Crossing would provide the basis to supply potential mine loads at Minto and Carmacks Copper with WAF surplus hydro energy. Development beyond Pelly Crossing to Stewart Crossing would interconnect the WAF and MD grids, thereby accessing surplus MD capacity for WAF in the near term. The full project with interconnection of the two grids would provide about 6 MW and 15 GW.h/yr of hydro energy to WAF, with this contribution decreasing as the MD load grows.

[8] This project concept would increase the licensed full supply level by 0.3 meters. The lake would not experience water levels higher than are currently experienced. No environmental studies on this specific project concept have been completed to date.

4.3.2 Aishihik 3rd Turbine

The Aishihik 3rd turbine project (current capital cost forecast of $7 million for 7 MW[9]) has long been considered as a relatively cost-effective means to add material new capacity to the WAF system, as well as a modest amount of new hydro energy.

Review of the system capacity constraints as part of the Capacity Planning Criteria review indicates that the capacity value of Aishihik 3rd turbine is extremely modest (about 600 kW under an LOLE of 2 hours/year, 0 MW under N-1) in the absence of a second Aishihik transmission line. This is because there is already a disproportionate amount of WAF generation at risk of an Aishihik transmission line outage, and the firm load carrying capability of WAF (under a probability-based assessment approach such as LOLE, or an N-1 approach) is not aided by further capacity development at Aishihik.

However, there remain two other enhancement aspects of the Aishihik 3rd turbine that cannot be ignored:

- First, there are certain circumstances where an Aishihik 3rd turbine could be valuable capacity to WAF (most notably if an Aishihik 2nd transmission line were developed, but also with major future generation development elsewhere on WAF which would reduce the relative weighting of Aishihik in the generation mix).
- Second, and likely of greater near term value, the long-term energy value of the Aishihik 3rd turbine (estimated at 5.4 GW.h per year under high load scenarios and new Water Licence terms) can be of value to WAF and can potentially yield diesel unit cost savings to offset the Aishihik 3rd turbine capital cost[10].

The Aishihik third turbine also provides material added near term enhancement benefits in displacing peaking diesel energy generation on the WAF system (as well as enhancing the ability to maintain maximum secondary sales revenues) while WAF surplus hydro is still available. This is because the presently installed firm winter hydro capability is only 54.4 MW (30 MW at Aishihik and 24 MW at Whitehorse plus 0.4 MW for Fish Lake) with normal winter hydro capacities in the range of 56-58 MW (i.e., in non-drought years). Consequently at the present time the maximum WAF load that can be allowed before diesel units must be started (and secondary sales interrupted) is a maximum of about 54 MW or less. With the addition of 7 MW of new hydro capacity at Aishihik, the operation of peaking diesel

[9] The $7 million cost estimate is currently under active review and refinement to reflect current pricing.

[10] The potential energy of 5.4 GW.h/yr represents an annual capacity factor of only 8.8% for the 7 MW unit; however, offset cost savings of about $1 million or more per year will occur if this displaces diesel fuel generation at 65 cents/litre cost. Base Case loads are not sufficient to yield any material diesel fuel displacement in the near term, but this starts to occur before 2025. Peaking diesel savings, which are discussed separately, are also material during this period under Base Case assumptions.

(and interruption of secondary sales) will not occur until closer to 61 MW. This can lead to material savings in WAF diesel generation starting when the unit comes into service (ranging under Base Case conditions from 0.4 GW.h a year in 2009 to as high as about 6 GW.h per year over the period of the Resource Plan). This effect also is expected to result in an increased number of hours of secondary sales availability and consequently secondary sales revenues[11] (this benefit has not been quantified).

The Aishihik 3rd Turbine is already authorized in the renewed water licence. Approximately 20-24 months are estimated to be needed from commitment until it comes into service (i.e., time needed for remaining pre-decision final design and costing and tendering as well as for subsequent construction). It is assumed that the project, if committed, would at the earliest come into service in 2009.

4.3.3 Marsh Lake Fall/Winter Storage

Although the Whitehorse Rapids hydro generating station is a largely run of river plant, there is some modest storage available at Marsh Lake, controlled via the Lewes Dam (a control structure upstream of Miles Canyon).

Various options have been reviewed over many years to enhance the output of Whitehorse Rapids by increasing the ability to control Marsh Lake.

One option that was previously studied and not adopted in 1992 was a project called the “Marsh Lake Top Storage Project” which YEC investigated in 1991-92 at the request of the YUB, to raise the licenced maximum storage on Marsh Lake by five feet (as well as associated lake level impacts on Tagish and Bennett Lakes). A study produced at that time for YEC estimated a requirement for only $760,000 (1992$) of physical works to the Lewes Dam control structure, but likely well over $25 million (1992$) in mitigation costs related to significant adverse impacts on many properties and developments affected by the higher water levels (YEC noted to the YUB that the company considered the study’s estimates to be low). Consequently, YEC recommended in the 1992 Resource Plan that it not proceed with the project, and the YUB agreed with this recommendation in its 1992 Report.

The Marsh Lake Fall/Winter Storage project under consideration today is a fundamentally different project than that considered in 1992. In this case, the project involves seeking changes to the Whitehorse Rapids water licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake under

[11] The impact on secondary sales quantities from hydro peaking resources such as the Aishihik Third Turbine has not been assessed. At certain loads, the Third Turbine may also reduce somewhat the availability of surplus power for secondary energy, as the water would be used to avoid baseload diesel and consequently no longer be “surplus hydro”. However, this is not expected to occur until the system is near the full utilization of hydro capability and only for a limited number of years.

certain conditions in the fall and early winter, in order to enhance Yukon River flows during the coldest months of winter[12]. The effect of the revised water licence would be as follows:

- **In non-flood years:** The licence revision would allow Yukon Energy to reduce Marsh Lake outflows from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period.
- **During flood years:** In years where Marsh Lake levels are at flood stages, no change would be made during August and September until after flood levels subside. Similar to existing rules, once the floods have subsided, water levels would be controlled to reduce further spillage in fall and early winter months (at a level about one foot higher than presently allowed), to allow the water to be used instead during the peak winter generation period. In all cases, the water levels would remain within the lake level limits currently experienced (i.e., the peak level that YEC is allowed to maintain by use of Lewes Dam would be below the natural high water levels experienced in the lake during uncontrolled summer periods). There would be no effect on the flood levels experienced on Marsh Lake.
- **During drought years:** Yukon Energy is currently permitted to help alleviate summer drought levels on Marsh Lake through “early closures” of the Lewes Dam (as early as July 7 in extreme droughts). These provisions would remain, and would likely be adapted somewhat to further alleviate summer drought conditions to ensure the lake reached the full controlled supply level (as revised) in each year.

Environmental licencing activities for the project have not been initiated. Studies will need to confirm the extent (if at all) to which the project may affect water levels in lakes that extend into BC.

The Marsh Lake Fall/Winter Storage project has the potential to enhance the output of the Whitehorse Rapids hydro facility by about 1.6 MW and 7.7 GW.h/yr long-term average hydro energy (actual enhancement will depend on load conditions assumed and revised maximum licence level allowed, which is assumed here to be one foot). Basically no new physical works are expected to be required for this project.

[12] During uncontrolled periods of summer and fall (when YEC has no control over the lake and it is operating under an entirely natural regime), Marsh Lake has been known to peak at two feet above the Yukon Energy “controlled maximum” level currently provided for in the water licence, and to typically peak at least one foot above the “controlled maximum” level. The specific revision sought to the water licence would be to change the licenced “controlled maximum” level that YEC can maintain at Marsh Lake upwards by likely in the range of one foot, i.e., the proposed licence revision will still be well within the normal natural levels experienced on the lake.

Costs of the project relate almost entirely to environmental licencing and mitigation, which are very difficult to predict. Given the relatively limited potential for physical or environmental effects (but recognizing the potential for notable public interest in ensuring full review of all potential effects) the costs of the project are not expected to exceed $1 million. Licensing and other pre-decision activities are assumed to require a year such that the project could potentially come into service in 2007 (in time to be of value in addressing the 2007/2008 winter peak).

4.3.4 Carmacks to Stewart Transmission Line Project

The proposed 138 kV Carmacks to Stewart Transmission Line would extend the WAF system north from Carmacks generally along the Klondike Highway to at least Pelly Crossing, and potentially as far as Stewart-Crossing in order to provide full interconnection with the MD system. Interconnection of the WAF and MD grids would provide near term capacity and energy benefits to the WAF system.

If the project is developed from Carmacks to at least Pelly Crossing, potential new mine developments in close proximity to the new transmission line could have access to service with WAF surplus hydro energy. In particular, the Minto mine and the Carmacks Copper mine, located between Carmacks and Pelly Crossing, are both located in areas that could be serviced with the proposed line. Development only to Pelly Crossing, however, would not result in interconnection of the MD and WAF grids.

Costs to develop this project from Carmacks for full interconnection to Stewart-Crossing have been estimated at about $35 million (2005$). It is not currently economic for Yukon Energy, as a regulated utility, to develop this project since both the WAF and MD systems today have surplus hydro power and the line would not at this time displace the level of diesel fuel or other high cost generation needed to justify its costs. Accordingly, this project is being examined as a key Yukon territorial infrastructure initiative to meet a specific window of opportunity related to two potential new mines (Minto and Western Silver at Carmacks Copper) and current Yukon Government Infrastructure Funding.

The project is currently being advanced using Yukon Government funding for permitting and approvals activities, including licencing under the new *Yukon Environmental and Socio-Economic Assessment Act (YESAA)*, as well as for finalizing project final design and costing. If critical planning does not proceed in a timely way through 2006 using Yukon Government Infrastructure Funding, permits and other preparatory work will not likely be done in time to enable the project to help in the development of these two mines (based on the current planned development schedules for Minto in particular). Current planning is seeking to protect a potential in-service date for this project between mid-2008 and mid-2009.

The extent to which the ultimate project concept is developed in the near term will be determined based on available Yukon Government Infrastructure Funding as well as the mine development that will actually occur. The project's capital costs will not impact regulated utility rates to the extent that its costs are funded through Yukon Government grant funding or through customer contributions from mines connecting to the WAF grid. Rates charged to such mines for use of WAF power would need to be approved by the YUB in accordance with OIC 1995/90 (which requires that such rates at least cover utility costs of service evaluated on a Yukon wide basis).

Development of this project from Carmacks to Pelly Crossing is estimated to cost in the range of about $20 million (2005$). This extent of development, in combination with the two proposed mines being developed and connected (costs for "radial" lines to service Minto and Carmacks Copper sites will be addressed via normal utility and customer investment policies), would fully utilize WAF surplus hydro in the near term.

Extending the project fully from Carmacks to Stewart Crossing (a further likely capital cost (2005$) of about $15 million over and above the cost for the project from Carmacks to Pelly Crossing) would provide near term capacity and energy benefits for the WAF system related to interconnection of the WAF and MD systems. It is estimated that such interconnection would provide in the near term about 6 MW of net capacity benefit to WAF[13] as well as another 15 GW.h/yr of net long-term average hydro energy; these benefits would decrease in future as MD load grows (or if new industrial developments, such as reopening of the UKHM mine, connect to the MD system). The surplus hydro made available can yield

WAF economic benefits during the planning period through both diesel unit cost savings and extended maintenance of secondary sales revenues[14].

In assessing various alternatives related to the Carmacks to Stewart Transmission Line project, Yukon Energy is examining the net cost that could be funded through rates in order to make interconnection cost competitive with other options. This is based on the assumption that if the project was to be developed in the near term, the project's capital cost will be provided for through Yukon Government Infrastructure Funding as required to ensure no impact on regulated utility rates.

[13] This reflects 12 MW of installed MD firm capacity and MD peak load forecast (2008) of 5.9 MW.

[14] The present value (2005$) of these diesel cost savings and extended secondary sales revenues approximates only $1.2 million over the 20 year planning period under Base Case conditions; under Base Case including Mines conditions (which are likely to be required, at least in part, if the interconnection is to be developed at this time), and excluding consideration of any other opportunity projects, this present value increases to $4.7 million. (These present values assume a discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre for peaking and 3.9 kW.h/litre for baseload, diesel fuel prices at $0.65/litres (2005$), diesel O&M at $0.016/kW.h (2005$) and inflation at 2%/yr. No firm capacity benefit is included in these present values.)

Long term benefits from the Carmacks Stewart Transmission project connecting the two grids include: encouraging economic development along the corridor of the new line and its extended environment; enhancing overall power system reliability on these systems; and providing greater flexibility to accommodate future load and generation interchange between the WAF and MD systems as they are currently known. Potential benefits, for example, include the ability under certain load development scenarios to move surplus WAF power to serve major new mine developments in the MD grid region should they arise; or to move surplus MD power to the WAF grid region from potential new hydro developments in the MD grid or Pelly Crossing regions, as well as from potential future Mayo hydro plant enhancements.

The Carmacks to Stewart Transmission Line project (full interconnection) impact on WAF firm winter capacity, plus other new diesels as required to meet capacity requirements, is illustrated in Figure 4.9 (at Base Case loads and excluding consideration of any other non-diesel capacity enhancements).

- The Base Case capacity shortfall in 2012 with interconnection of the MD and WAF grids is approximately 13.1 MW, and is assumed in Figure 4.9 to be met through 16 MW of added diesel units (4 MW in 2009, 4 MW in 2010, and 8 MW in 2012).
- Under other forecast conditions examined, the capacity shortfall in 2012 with the Carmacks to Stewart Transmission Line project (full interconnection) is 8.7 MW (Low Sensitivity case), about 15.8 MW (Base Case including Mines), and about 21.5 MW (High Sensitivity including Mines).

Figure 4.9:
Carmacks to Stewart Transmission Line in 2008

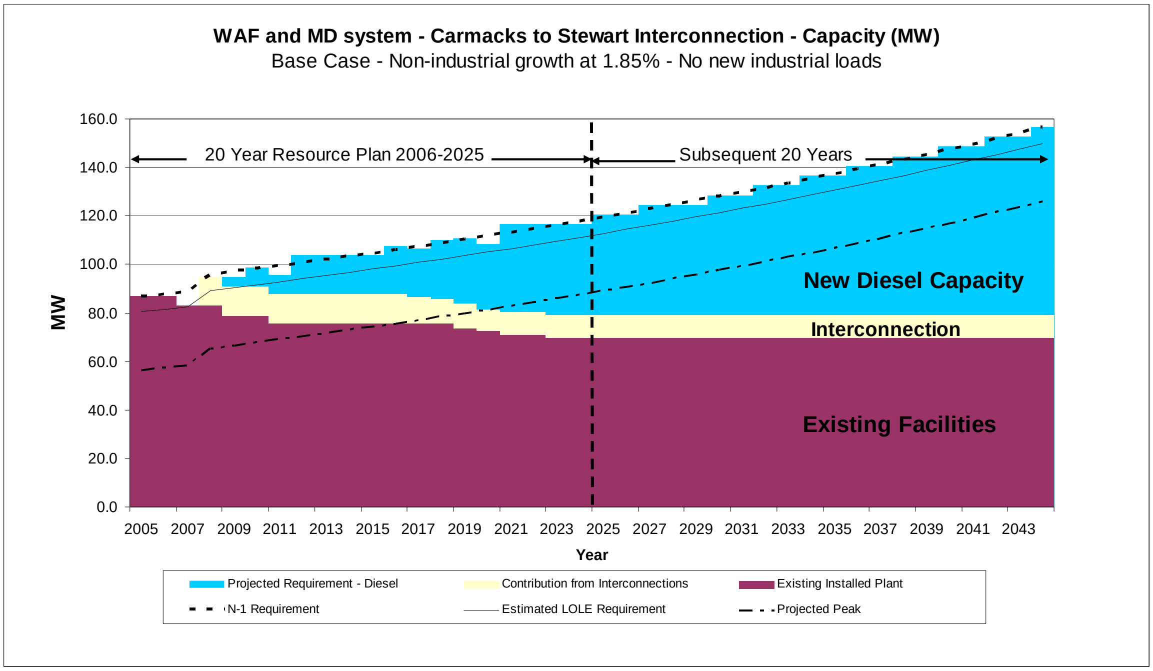
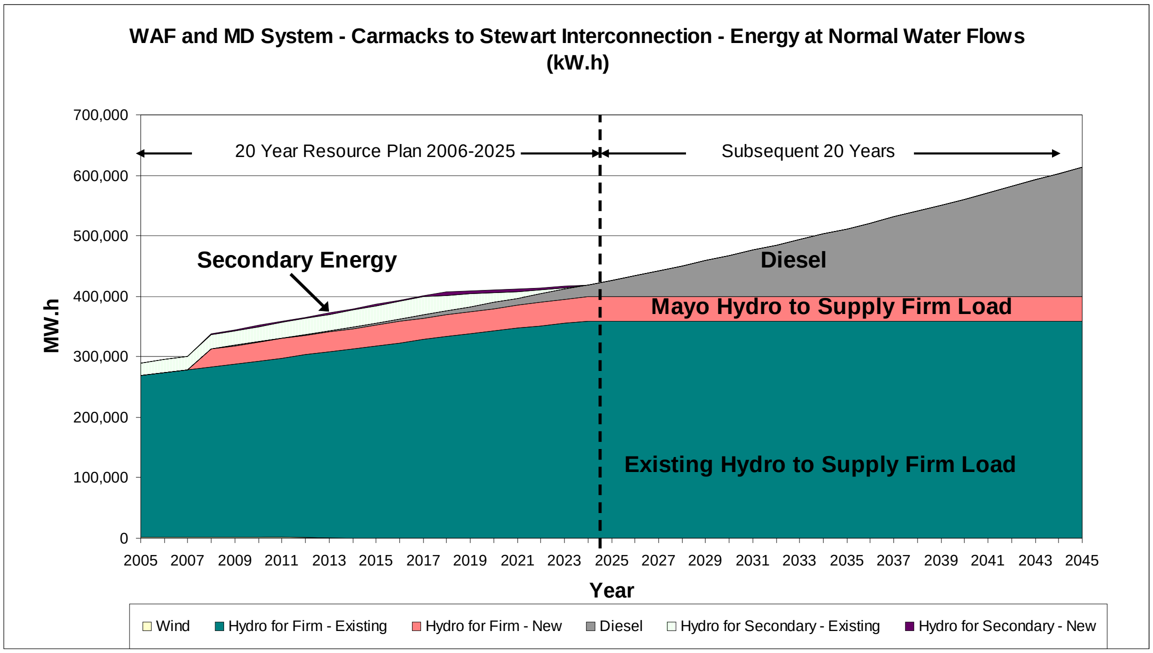


Figure 4.10 reviews the hydro and diesel energy loads under the Base Case forecast with interconnection of the MD and WAF grids, indicating surplus hydro remaining throughout the 20-year planning period.

- Under Base Case forecast conditions including the Minto and Carmacks Copper Mines, the full interconnection project has the same surplus hydro after the mines close in 2016 and 2018.
- Under the High Sensitivity case including these mines, the full interconnection project has no surplus hydro available after the mines close.

Figure 4.10:
Carmacks to Stewart Transmission Line in 2008



4.3.5 Overview of Major Capacity-Related Project Options

Under the new capacity planning criteria, the WAF system is facing a capacity shortfall in the very near term. As reviewed in Section 4.2, the magnitude of the capacity shortfall depends in part on the load growth that occurs over the next few years (including the extent to which new mine loads, if developed, are connected to WAF through new transmission facilities). However, even under the lowest load growth scenarios, the shortfall approaches 15 MW by 2012, which is a very material scale for the WAF system (which peaks at about 56 MW today).

Facing this requirement, Yukon Energy has identified three major replacement and expansion project options (beyond the “opportunity” project options already noted) that have the potential to largely or entirely address major capacity shortfalls by 2012 on the WAF system:

- **Mirrlees Life Extension Project (14 MW):** One option that requires consideration is a major refurbishment of the three existing Mirrlees units at Whitehorse to reclaim the full 14 MW nameplate ratings and extend the life of the units for 10 years or more. The project would require a full “tear down” overhaul of the three units as well as upgrading to various shared systems in the Whitehorse diesel plant. As the project would only provide 14 MW of capability, it would need to be combined with other projects to meet the full 2012 shortfall assumed based on retirement of these Mirrlees units (i.e., to achieve the full 15 MW to 27 MW under the various scenarios in Section 4.2). This option is reviewed in more detail below (see Section 4.3.6).

- **Whitehorse Diesel Replacement/Expansion Project (unlimited MW):** This flexible option is available to meet the full range of possible new capacity requirements in near term (up to the full high load scenario requirements of 27 MW by 2012). New units of any type or combination could be added to the system incrementally as required. In all likelihood the units would be installed as replacements for the retired Mirrlees (in the bays vacated by the retirements) and, if undertaken with large units such as modern 8 MW Wartsila gensets (or larger, such as 11 MW units), could largely or entirely be accomplished within the confines of the existing site. In addition, other major resource options that are not sufficiently large to address the entire 2012 shortfalls may be combined with a smaller scale of new diesel installation. This option is reviewed in more detail below (see Section 4.3.7).

- **Aishihik 2nd Transmission Line Project (15 MW under N-1 criteria, 8.0 MW under LOLE criteria):** As discussed in detail in Section 3.3, the largest single factor influencing the reliability and risk profile of the WAF system today is the non-redundant nature of the Aishihik transmission line. A major rationale for maintaining substantial "stand-by" diesel in Whitehorse is to address the risks of an Aishihik line failure. One project option that consequently merits consideration is a "twinning" of the Aishihik transmission line to provide required redundancy. Were such a facility to be put into service to provide complete redundancy, the N-1 criteria would be revised to indicate 15 MW as the largest single contingency (based on one of the hydro units at Aishihik, which are the largest single units on the system) rather than 30 MW currently arising from a potential loss of the line. Under the N-1 criteria, this would currently be a 15 MW benefit to the load carrying capability of the system. Under the LOLE criteria, also as noted in Section 3.3, the benefit from a redundant Aishihik transmission line would currently be about 8.0 MW. In addition, this option enables the opportunity for additional firm capacity benefits related to other potential enhancements at the Aishihik generating station such as the Aishihik 3rd Turbine, as well as the potential for re-runnering (as discussed below). As the Aishihik 2nd Transmission line project would currently only provide 15 MW of new load carrying capability, it would currently need to be combined with other projects to meet the full 2012 shortfall (to achieve the full 15 MW to 27 MW under the various scenarios in Section 4.2). This option is reviewed in more detail below (see Section 4.3.8).

Aside from relying only on diesel expansion/replacement, none of the above major options on its own is likely to address the full WAF capacity shortfall expected in the near term (to 2012). For initial review below, it is assumed that additional diesel engines are the default option to be used as required with each of the other options in order to meet the full near term capacity shortfall. Later, in section 4.4, optimum combination of these options is examined under a range of planning assumptions.

4.3.6 Mirrlees Life Extension Project

As noted in Section 4.1, the Whitehorse Diesel Units WD1, WD2 and WD3 are the three largest units in the Whitehorse diesel plant. Although planned for retirement at an earlier date, Yukon Energy was able to delay the retirement of the units largely as a result of the closure of the Faro Mine.

BC Hydro's Condition Assessment in 2004 recommended that the retirement of these units be seriously considered if significant further use was anticipated (*Section 3.1: Current Facilities Condition Assessment*). Assumptions regarding retirement of these units have at various times been based to a greater or lesser extent on the following cited issues:

- The units' condition is becoming unacceptably poor, and would require substantial investment to bring them back up to a utility quality condition;
- The units are poorly suited to the current operating regime of stop-and-start operation;
- Parts and technical support are lacking and expensive; and,
- The units are expensive to operate and maintain.

Despite these limitations, the retirement of the Mirrlees engines will necessitate major new capacity-related investment in the near term (particularly under the new capacity criteria, but also to a lesser degree even under the previous criteria). In addition, the YUB recommended in its 1992 Report on the utilities' Resource Plan that before the Companies commit to the construction of a supply option they should critically assess a number of factors including "the necessity for diesel retirements". As a result, Yukon Energy is currently undertaking a critical assessment of the potential for a "Life Extension Project" for the units. Such a project must, at a minimum, ensure the above concerns with respect to condition can be fully addressed (including reclaiming the previous full 14 MW combined nameplate ratings).

If feasible, such an option would materially reduce capacity shortfalls in the next five to six years; it would also materially reduce capital costs relative to those needed for any other available option to meet WAF near term capacity requirements. Such an option, if practical, is expected to involve capital costs (2005$) potentially in the order of $0.5 million to $1.0 million for each unit (with material risks that costs could not be readily estimated with any degree of certainty before the project is undertaken, as the status of internal parts and mechanisms cannot be readily ascertained until the tear-down is underway). In addition there would be substantial initial work in the order of $1.0 million to $1.5 million related to shared aspects of the Whitehorse diesel facility systems requiring material improvements (such as cooling systems, fuel delivery systems, foundation, etc.).

There remain two key concerns with the Mirrlees: the cost and availability of parts and support from the manufacturer, and the suitability of the units to the current Yukon operating environment.

With respect to the manufacturer, it will not be prudent for Yukon Energy to proceed with any Mirrlees Life Extension project unless Yukon Energy can receive clear and reliable assurances that the manufacturer can provide full competent and cost-effective parts and technical support for these units for the next 10-20 years. Recent Yukon Energy experience indicates this concern to be very material. Yukon Energy is in the process of assessing the manufacturer's claims that they can continue to provide competent support on these units, including discussing Yukon Energy's recent experiences with the manufacturer, and seeking references from other utilities who have pursued a similar course of action.

With respect to the operating environment, despite a full tear-down overhaul, the Mirrlees units will remain low speed base load units which are poorly suited to the current Yukon operating environment (stop-and-go operating, limited running hours). This limitation cannot be fixed. However, it is not sufficiently severe to rule out a Life Extension project option, given competitiveness on other grounds as well as the expected use primarily for reserve rather than planned operation purposes (see Section 4.4 regarding "Assessment" below).

Yukon Energy is aware that Northwest Territories Power Corporation ("NTPC") has plans to retire their two KV16 Mirrlees units in Yellowknife in the next number of years (NTPC has already retired a similar unit in Inuvik; the Yellowknife units are similar in running hours to Yukon Energy's units, but about six to seven years newer). The NTPC retirement plans are due primarily to two concerns: part and technical support availability, and suitability to a stop-and-go unattended operating environment. Further discussions with NTPC are planned to compare experiences on these two matters.

If the Mirrlees Life Extension project is pursued and 14 MW of capacity is restored for these units, by 2012 additional diesel capacity will still be required under the capacity planning criteria (capacity shortfalls of 4.7 MW would exist under the Base Case, 0.7 MW under the Low Sensitivity Case, 7.5 MW under the Base Case with mines, and 12.7 MW under the High Sensitivity Case with mines).

Overall, likely costs (2005$) for the Mirrlees Life Extension project to 2012 can be estimated for screening purposes as follows, assuming that added requirements beyond 14 MW are met though additional diesel capacity[15]:

- **Base Case:** Mirrlees Life Extension at $3.0 million to $4.5 million, plus 4.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total ***$6.8 million to $8.7 million***.
- **Low Load Sensitivity:** Mirrlees Life Extension at $3.0 million to $4.5 million plus 0.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$3.6 million to $5.1 million***.
- **Base Case with Mines:** Mirrlees Life Extension at $3.0 million to $4.5 million, plus 7.5 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total ***$9.0 million to $11.3 million***.
- **High Load Sensitivity including Mines:** Mirrlees Life Extension at $3.0 million to $4.5 million, plus 12.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total ***$13.2 million to $15.9 million***.

In summary, the capital cost (2005$) of the Mirrlees Life Extension Project plus other diesels as required to meet peak loads to 2012 is expected to cost in the range of $6.8 million to $8.7 million, with potential under various load developments to range from $3.6 million to as high as $15.9 million.

Timing with respect to the Mirrlees Life Extension is expected to be quite flexible. Major tear-down overhauls can likely be scheduled on six months notice, and major upgrades to common facilities can likely be staged so as to meet in-service requirements of the overhauled units (although the lead times will in all likelihood be slightly longer than for overhauls, due to design requirements). The project can also likely be staged over a number of years (summers) if preferable. The project is assumed to be suitably organized in an orderly fashion by sequencing one unit per year from 2007 to 2009 (starting with the largest) with common facilities upgrades occurring in 2007. Work on the existing units and facilities that disrupt current capability must occur during summer months (as the units are needed during winter to provide firm capacity).

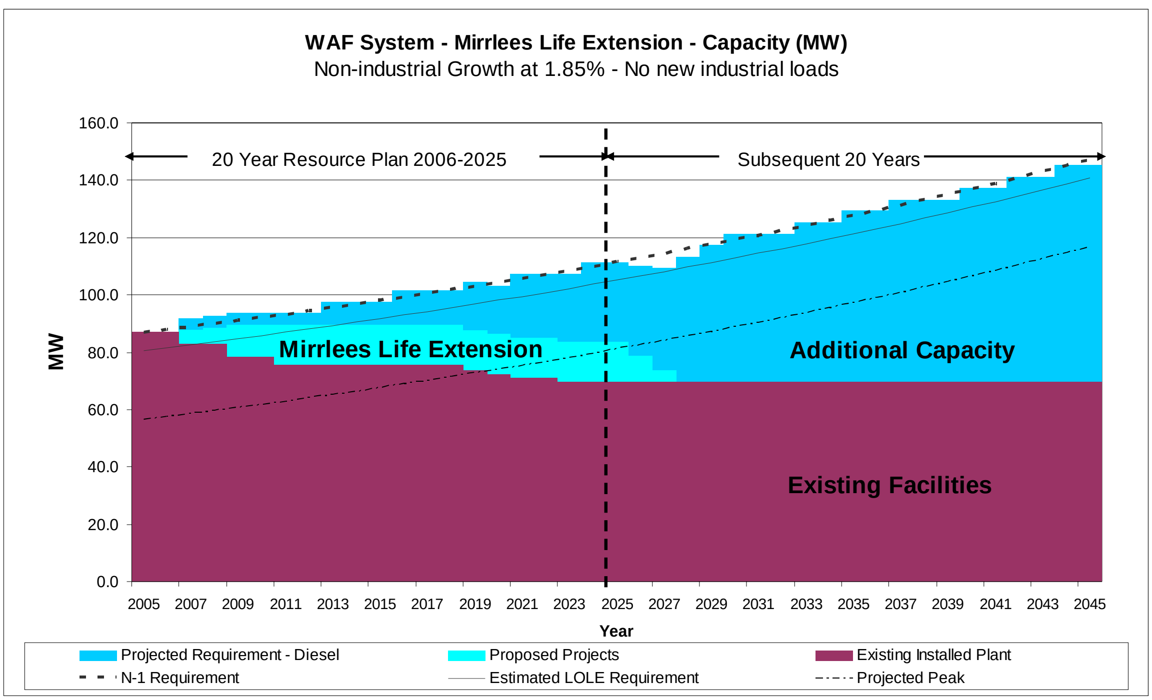
[15] See Section 4.3.7 for a more detailed review of costs for additional diesel units. As a rough measure for screening purposes, diesel units installed for capacity reserve purposes without a need for major "Green Field" support systems (e.g., fuel tanks, substations, control systems) are estimated to cost (2005$) in the range of $800,000 to $900,000 per MW (e.g., $3.2 to $3.6 million for a 4 MW unit). Under the Mirrlees Life Extension option the Whitehorse diesel plant facilities would be utilized for the Mirrlees units, and costs for additional diesels therefore may tend to be higher than otherwise assumed, particularly if a new diesel generation site would need to be developed for these added units.

For the added diesel units that are assumed to be required, issues also arise with respect to locating such diesel units if the entire Mirrlees Life Extension project is pursued. Were the three Mirrlees to be retired, the three "bays" of the existing diesel plant would allow three new units to be installed (units of 8 MW are expected to fit readily into the existing bays, allowing for up to 24 MW of new capacity; units of 11 MW or larger may also fit, but require further consideration). However, if the Life Extension is pursued, these bays will be in use by the Mirrlees and new units will require modifications or expansions to the existing building, or pursuit of other options with respect to unit location.

The Mirrlees Life Extension project impact on WAF capacity, plus other diesels as required to meet capacity requirements, is illustrated in Figure 4.11 (at Base Case loads). This figure focuses on a Life Extension project to add 20 years to the lives of the Mirrlees units. Under this forecast scenario, one new diesel unit (about 4 to 5 MW) would be required in 2007.

One potential variation on implementing the Life Extension project could involve Life Extension of the two largest Mirrlees units (10 MW total) combined with replacement of the smaller third Mirrlees unit (4 MW) with a larger 8 or 11 MW new unit. Under this variation, there would be no need for any other new diesel unit by 2012.

Figure 4.11:
Mirrlees Life Extension



4.3.7 Whitehorse Diesel Replacement/Expansion Project

The Whitehorse Diesel Replacement/Expansion project encompasses various potential concepts of meeting all capacity requirements (including those driven by Mirrlees retirements) using new diesel units at Whitehorse. This could include various combinations of unit sizes (e.g., approximately 4 MW or 8 MW or potentially others such as 11 MW or 15 MW) sequenced as needed to meet load requirements as well as other implementation practicalities. Ongoing investigations are examining issues and costs related to alternative ways to implement this generic option, including common plant upgrade requirements.

Purchase of new diesel units is likely the most flexible approach possible to addressing capacity shortfalls, as units can be sourced that are properly suited to standby use in a wide range of sizes and specifications. However, due to presently high worldwide demand for new diesel units, lead times for new orders from initial commitment through to in-service (including engineering, manufacture, delivery, installation and commissioning) can be on the order of 18 months, which is well above the traditional lead time for new units. As note earlier, work on the existing units and facilities that disrupts current capability must occur during summer months (as the existing units are needed during winter to provide firm capacity).

Diesel units installed at the current Whitehorse plant, without the need for major "Green Field" support systems (e.g., fuel tanks, substations, control systems), are estimated to cost (2005$) in the range of $800,000 to $900,000 per MW[16]. Estimated capital costs (2005$) to 2012 for screening purposes of the Whitehorse Diesel Replacement/Expansion Project are as follows:

- **Base Case:** 18.7 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$15.0 million to $16.8 million***.
- **Low Load Sensitivity:** 14.7 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$11.8 million to $13.2 million***.
- **Base Case with Mines:** 21.5 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$17.2 million to $19.4 million***.
- **High Load Sensitivity including Mines:** 26.7 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$21.4 million to $24.0 million***.

[16] By way of example, based on prices recently quoted to YEC and estimates for costs to install and commission at Whitehorse, a 4.3 MW EMD 16-265H using 6.9 kV generators has been estimated to cost (2005$) about $730,000 per MW ($3.1 million), and a 7.8 MW new 7.8 Wartsila 18V32 using 13.8 kV generators has been estimated to cost (2005$) about $740,000 per MW ($5.8 million). In addition, common plant upgrade costs of $1.0 million have been estimated to apply in each case (assuming installation at the current Whitehorse plant to replace the Mirrlees units, which are assumed to be removed and replaced with from 12 to 24 MW, depending on the unit size selected). Together, these costs average at between $786,000 and $808,000 per MW (depending on the units size selected).

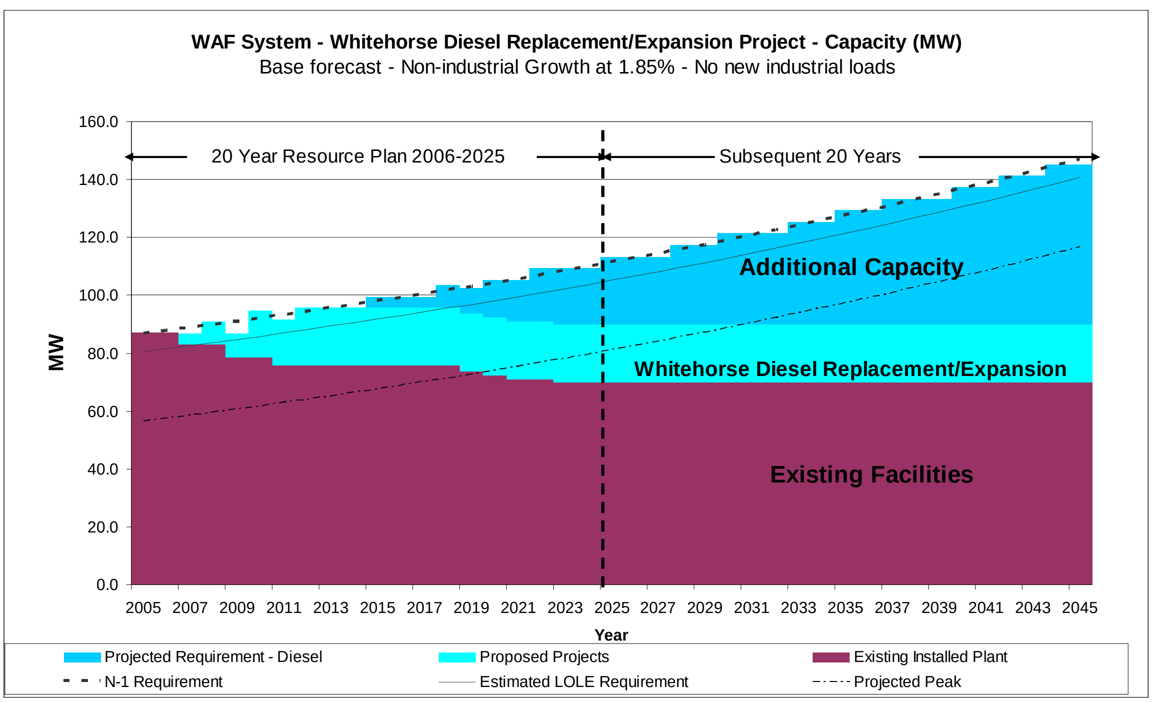
In summary, the capital cost (2005$) of the Whitehorse Diesel Replacement/Expansion Project as required to meet peak loads to 2012 is expected to be in the range of $15.0 to $16.8 million, with potential under various load developments to range from $11.8 million to as high as $24.0 million.

For the first three units installed, there is little issue with space or support systems at the current Whitehorse diesel plant, as the three bays vacated by the retired Mirrlees are of sufficient size to accommodate the noted 4 MW or 8 MW units and perhaps up to 11 MW or larger.

However, issues begin to arise if either a) more than three units are required in the sequence to 2012 (as would occur with new units of 4 MW rather than 8 MW, or would occur under the High Load Sensitivity Scenario with Mines which requires more than three 8 MW units) or b) units are required at a rate faster than the Mirrlees are planned to be retired. If this arises, modifications or expansions will be required to the existing building, or other options required regarding unit location.

The Whitehorse Diesel Replacement/Expansion Project impact on WAF capacity is illustrated in Figure 4.12 (at Base Case loads and assumed increments generally at 4 MW units). Under this forecast scenario, an added diesel unit would be required in 2007, another 4 MW unit would be required in 2008, an 8 MW unit would be required in 2010, and a further 4 MW unit in 2012.

Figure 4.12:
Whitehorse Diesel Replacement and Expansion



4.3.8 Aishihik 2nd Transmission Line Project

The Aishihik Transmission Line is a key component of the WAF 138 kV system. It connects 30 MW of hydro generation from Aishihik to major load and generation centers at Whitehorse and beyond. The Aishihik 2nd Transmission Line Project is a near term option for potential development under the new capacity planning criteria if the existing Mirrlees diesel units at Whitehorse are confirmed to be retired. The project concept is to establish a redundant circuit for Aishihik generation to reach the remainder of the WAF system at Whitehorse.

The net effect of this project under forecast loads would be a reduction in the N-1 capacity planning criteria "reserve" currently of about 15 MW, approximately equal to adding 15 MW of new diesel units. Under the LOLE criteria, the Aishihik 2nd Transmission Line project benefit currently is 8.0 MW. However, under the Base Case forecasts with current facilities, the N-1 criteria is the key factor in requiring new capacity in the near term[17]. Subject to timing issues for its in-service, the project would eliminate the need for any new capacity under Base Case load forecasts until 2012.

Pending results of the current Mirrlees Life Extension investigations, Yukon Energy has not proceeded with material work to date on potential routing options for the Aishihik 2nd Transmission Line project. There exist a number of options to connect to any of 3 substations in the Whitehorse area, or alternatively potentially to the WAF grid line north to Carmacks. Regardless of the routing, the project requires that full redundancy on the delivery of power to the Whitehorse is to be established, including substation components and Whitehorse area transmission connections.

Preliminary costing (2005$) indicates a transmission line development cost (planning, permitting, design and construction) for the simplest project alternative roughly paralleling the existing line on the order of $16 to $19 million. The total costs (2005$) to meet capacity requirements to 2012 with the Aishihik 2nd Transmission Line project are therefore currently estimated for screening purposes as follows:

- **Base Case:** Aishihik 2nd Transmission Line at $16 to $19 million, plus 4.5 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$19.6 million to $23.1 million***.
- **Low Load Sensitivity:** Aishihik 2nd Transmission Line at ***$16 to $19 million*** fully satisfies the capacity requirements to 2012.

[17] In contrast, if the Aishihik 2nd transmission line was to be built, the LOLE criteria would become the driving factor by 1.1 MW.

- **Base Case with Mines:** Aishihik 2nd Transmission Line at $16 to $19 million, plus 13.5 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$26.8 million to $31.2 million***. The substantial diesel requirement over and above the Base Case is due to the fact that with 9 MW of mining loads, the LOLE criteria becomes the driving consideration in new capacity, which only credits the Aishihik 2nd transmission line project with 8.0 MW rather than the 15 MW under the N-1 criteria.
- **High Load Sensitivity including Mines:** Aishihik 2nd Transmission Line at $16 to $19 million, plus 18.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$31.0 million to $35.8 million***.

In summary, the capital cost (2005$) of the Aishihik 2nd Transmission Line Project plus additional new diesel units as required to meet peak loads to 2012 is expected to be in the range of $19.6 to $23.1 million, with potential under various load developments to range from $16 million to as high as $35.8 million. In particular, costs under this scenario (without examining any other potential benefits noted below) are materially increased by the presence of the potential mining loads.

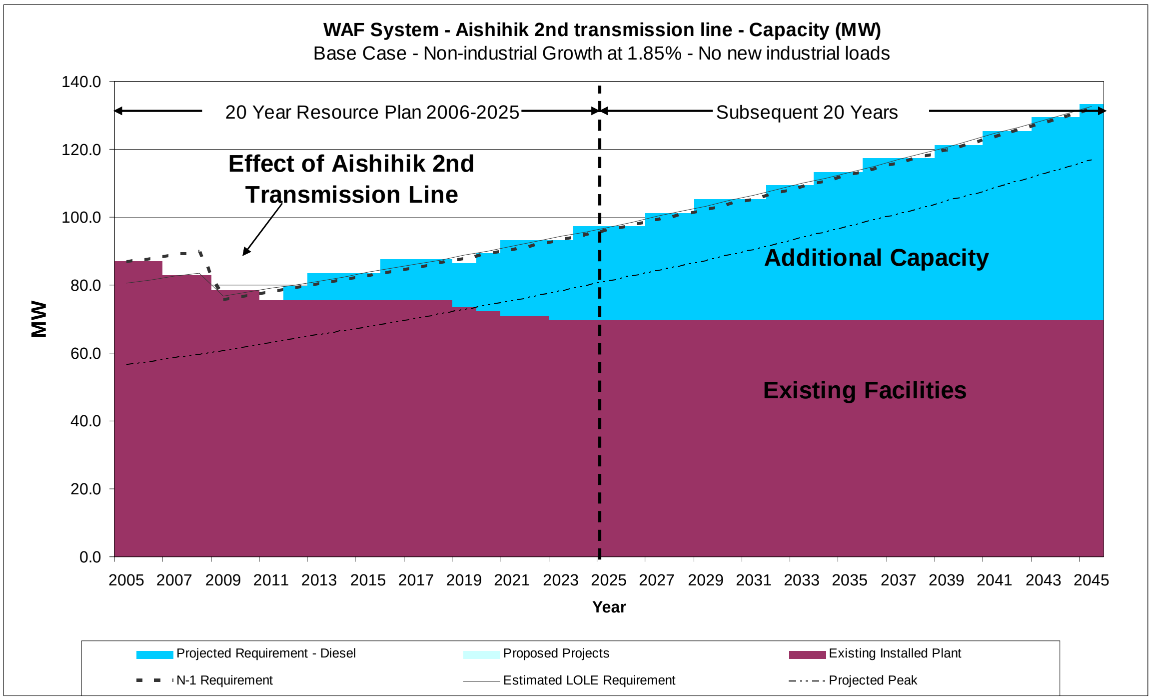
The Aishihik 2nd Transmission Line project would somewhat reduce operating costs compared to diesel in the near term as the project would allow for greater flexibility to keep Aishihik on-line during line maintenance activities which may serve to reduce diesel energy generation that would otherwise be required. In contrast, an equivalent 15 MW of diesel units would require some new spending on diesel fuel in order to maintain and exercise the units regularly.

The development of the new transmission line would involve much longer lead times from commitment to in-service than the other options noted above (potentially three years or more after a commitment to do detailed planning and construction), as well as be less flexible in the near term given the impact of an addition of 15 MW all at one time (compared to diesels which can be added in selected increments as desired). For the purposes of planning, it is not expected that an Aishihik 2nd Transmission Line could be in service any earlier than 2009, which would additionally raise concerns over capacity shortfalls in the 2006-2008 period (under the assumption that under Base Case conditions it may not be sensible to install sufficient new diesel engines (8 MW) to address this two to three year capacity shortfall).

In addition, due to the nature of transmission line contracting, it would not be possible to develop a materially more reliable estimate of the capital costs until such time as permitting and environmental approvals were completed, final tenders were received and contracts concluded (likely requiring a planning cost expenditure of about 10% of the capital cost, or about $1.6 to $1.9 million to get to this stage).

Figure 4.13 below illustrates the capacity criteria benefits of twinning the Aishihik line. Under Base Case assumptions, new diesel (about 4 to 5 MW) would not need to be added to the system until 2012.

Figure 4.13:
Aishihik Second Transmission Line 2009



In addition to ensuring existing Aishihik capacity can remain substantially more reliable to the system, the Aishihik 2nd Transmission Line project also has the benefit of enhancing the opportunity provided by two projects to provide additional capacity at Aishihik:

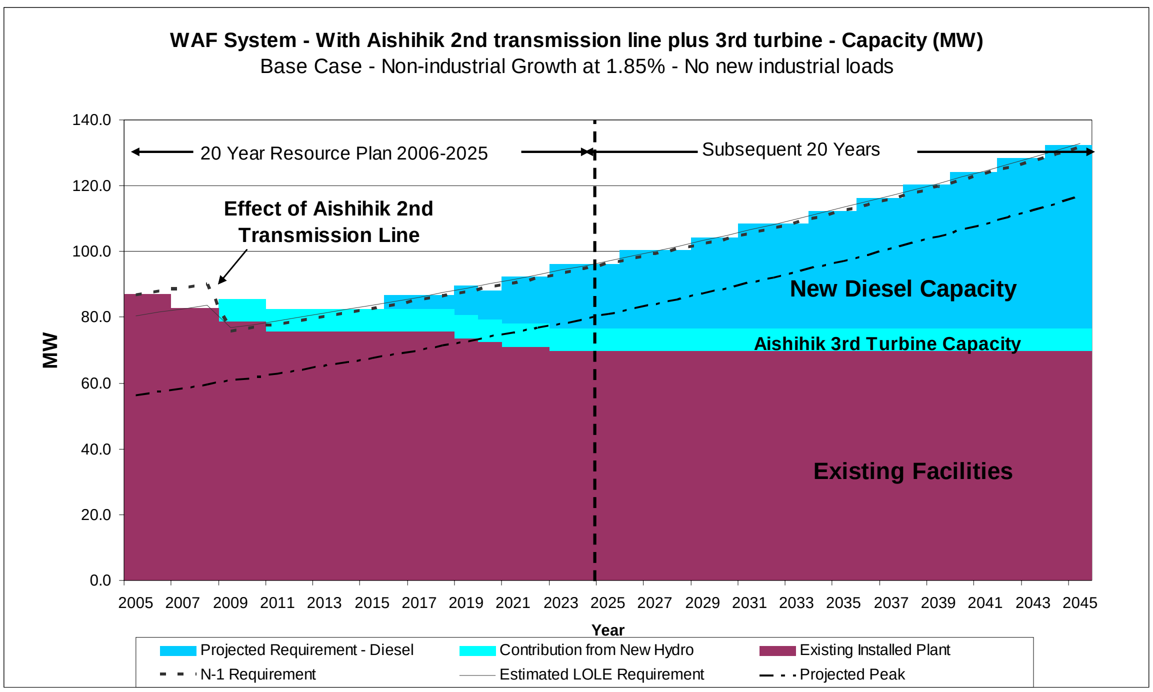
1. The 7 MW Aishihik 3rd Turbine.
2. A re-runnering of the existing Aishihik turbines for potentially up to 6 MW of added capacity.

The Aishihik 3rd Turbine is discussed in detail in section 4.3.2. At this time, there is insufficient definition on the potential Aishihik re-runnering project to determine likely costs and practical full capabilities; however, re-runnering projects in other jurisdictions are frequently pursued as cost-effective sources of new capacity and/or energy.

In the event the Aishihik 3rd Turbine project is pursued independently as an “opportunity” project in the near term, development of the Aishihik 2nd Transmission line (under Base Case load conditions) would provide 22 MW of firm capacity, which would allow for a full retirement of the Mirrlees engines and defer until 2016 the need for any new diesel units on the WAF system. However, without an Aishihik 2nd Transmission line, the Aishihik 3rd Turbine project cannot be considered reliable capacity under the N-1 criteria and only 0.6 MW of the 7 MW can contribute to the Load Carrying Capability under the LOLE criteria. Accordingly, the added capacity value of the Aishihik 2nd Transmission Line become 22 MW under the N-1 criteria and 14.4 MW under the LOLE criteria[18].

Figure 4.14 below notes, under Base Case assumptions, the added benefit of a third turbine separately from new diesel (in this case the 3rd Turbine is assumed to be placed in service in 2009, with new diesel not required until 2016)[19].

Figure 4.14:
Aishihik Second Transmission Line in 2009 (with Aishihik 3rd Turbine in 2009)



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[18] Under N-1 criteria with the Aishihik 2nd Transmission Line, a full 37 MW (30 MW existing plus 7 MW for 3rd Turbine) is now recognized at Aishihik (versus no MW recognized without the 2nd Transmission line), less 15 MW for loss of one unit (which once again becomes the largest single contingency event at the time of winter peak), resulting in a net firm capacity gain due to the 2nd line of 22 MW. Under LOLE criteria, the Aishihik 2nd Transmission Line benefit is 8.0 MW regarding the existing Aishihik capacity plus 6.4 MW regarding the Aishihik 3rd Turbine (0.6 MW of the 7 MW would be recognized without the 2nd transmission line), resulting in a net firm capacity gain due to the 2nd line of 14.4 MW.

[19] Approximately 20-24 months are estimated to be required from commitment of the Aishihik 3rd Turbine project until it comes into service. Accordingly, this project could, if so required, be brought into service by as early as during 2008.

4.3.9 Supplemental Project Options

Supplemental project options can serve to complement the major “opportunity options” as well as the major replacement and expansion options noted above. These supplemental project options have the potential to increase capacity, but are not of a sufficient size to materially address the near term capacity shortfall forecast for WAF. These options also remain relatively undefined at this time.

a) **Other facility enhancements that are preliminary and likely far too small to address the entire forecast shortfall:** Supply-side enhancement opportunities are limited by site and/or unit specific opportunities to increase winter peak capacity. Examples under consideration include re-runnering of the two existing Aishihik units (although any new capacity would be subject to the same N-1 constraints as the existing units), and re-runnering of Whitehorse hydro units WH3 and WH4.

b) **Projects without sufficient definition to pursue in the near term:** A range of possible longer-term projects related to the Southern Lakes, as well as Atlin Lake Top Storage have the potential to increase capacity and energy outputs of the Whitehorse Rapids plant (as well as potentially to establish new generation south of Whitehorse). However, these projects are not considered to be potential options to meet near term capacity focused needs, as they are not sufficiently defined or studied at this time. Yukon Energy is currently undertaking a study to update and refine its knowledge of the specific hydrology of the southern lakes area, but until this work is completed, it is difficult to know the potential for cost-effective water management (or hydro generation) structures in the region.

c) **Projects with no reliable capacity contribution:** New wind generation, small scale run-of-river hydro generation, solar, major new DSM initiatives or various other potential new generation technologies are not typically considered by utilities to provide reliable capacity towards meeting near term capacity shortfalls of the type forecast in Yukon.

d) **Projects that require major energy load to be economic:** New storage hydro projects, biomass generation (e.g., wood), and coal generation are not considered to be feasible cost effective options to meet near term capacity focused needs. These projects can only typically be developed when systems require both capacity and sustainable new energy that would otherwise need to be supplied by higher cost options; in Yukon’s case past experience has shown that these projects can only be developed on a cost-effective basis when there is sufficient energy being generated with diesel, and substantial certainty that this diesel generation would continue well into the future absent a major capital intensive new generation development of this type (see Chapter 5).

e) **Addition of new diesel generation capacity at Carcross (likely by YECL) of about 1 MW:** Carcross and the connections to Tagish are the only WAF communities of reasonable size (over about 300 people) which do not have local diesel generation installed. In the event that new diesel generation is required on WAF, it may be prudent to locate a small portion of this generation (likely about 1 MW) in the Carcross or Tagish area.

4.4 ASSESSMENT

Assessment of the above near term major project options (i.e., options costing $3 million or more for commitment before 2009) focuses on system optimization and economics for opportunity projects, and on requirement to address the new capacity planning criteria for capacity-related projects.

- **Opportunity Projects:** Assessment of the three identified opportunity projects is set out in Section 4.4.1 below. These three projects reflect both qualitative benefits from maximizing the use of existing investments and infrastructure, as well as quantitative economic benefits from enhanced hydro energy and/or capacity availability to serve loads.
- **Capacity-related projects:** Assessment based on the revised capacity planning criteria, as described in Chapter 3 (Section 3.4), is set out in Section 4.4.2 below. Under these criteria, and assuming retirement of the Mirrlees units, new capacity is needed on WAF under the Base Case in 2006 (0.7 MW), with an 18.7 MW forecast shortfall in 2012[20]. The MD system has no forecast capacity shortfalls by 2012 under the revised capacity planning criteria in the absence of new major industrial loads.

There is no economic opportunity in the near term to develop new capital intensive energy projects such as hydro or coal (without major new industrial loads at the level discussed in Chapter 5) outside of the identified opportunities regarding enhancements to existing facilities.

Resource options are assessed and/or screened over the near term and beyond, based on technical feasibility (including timing), cost efficiency and effectiveness, reliability, and risk (in particular risks related to future load requirements developing differently than indicated by current forecasts). Section

[20] Assessment based on the previous capacity planning criteria is not addressed. Under the previous criteria, and assuming retirement of the Mirrlees units, no new capacity would be needed on WAF under the Base Case until 2010 (0.6 MW), with a 5.6 MW forecast shortfall in 2012. Meeting these requirements would not require cost commitments by Yukon Energy of $3 million or more before 2009. However, even if the previous capacity planning criteria were still in place, it would remain relevant to assess the feasibility of 10 to 20 years Life Extension for the three Mirrlees diesel units at Whitehorse as a cost effective way to retain 14 MW of capacity capability on WAF.

4.4.3 below examines the expected effects of preferred near term projects on overall utility costs and rates.

4.4.1 Assessment of Opportunity Projects

There are three ways that the identified major opportunity projects can provide qualitative and quantitative benefits to Yukon power systems:

- **Peaking diesel fuel use reductions:** Although WAF loads today are at a level where surplus hydro exists on this system, peaking diesel is becoming required on the coldest days of the year and a reasonably high load growth rate is driving the system towards further requirements for peaking diesel each year. Expansion of Aishihik capacity is particularly beneficial in this regard until load growth in effect removes most of the opportunities for secondary sales.
- **Firm winter capacity benefits:** Certain enhancements to existing facilities can provide additional firm capacity to aid in meeting the WAF firm capacity shortfalls noted above. This applies to the Marsh Lake Fall/Winter Storage project and to the Carmacks to Stewart Transmission Line project, but does not apply to the Aishihik 3rd Turbine in any material way unless and until the Aishihik 2nd Transmission Line is developed.
- **Long-term average hydro energy benefits**: Finally, over the long-term, projects that bring new long-term average hydro energy can provide the ability to displace diesel fuel once loads grow to the point of diesel being required for baseload purposes (either through retail customer load growth or the addition of new industrial customers). This benefit applies to all three of the identified “opportunity” projects.

Table 4.2 provides a summary of the near term opportunity projects, including capital costs, in-service timing. Capacity and energy benefits, and present value assessments (for at least two options) of the long-term net diesel costs savings after consideration of project capital and operating costs.

Table 4.2:
Summary of Near Term Opportunity Projects to 2012 (2005$ millions)

PROJECT[21]	BASIS FOR PROJECT	PROJECT CONTRIBUTION[22]
IN PROJECT PLANNING STAGES (PRE-CONSTRUCTION ACTIVITIES, INCLUDING YUB REVIEW)		
Aishihik 3rd Turbine (2009) Capital cost: $7 million	Economic opportunity for "Supply Side Enhancement" to existing facilities.	• Hydro peaking capability (7 MW). • Long-term energy enhancement (5.4 GW.h/year). • no contribution to required firm capacity criteria without 2nd Aishihik Transmission. • Long term net diesel cost savings of $4.1 million (NPV, 2005$) under Base Case load forecasts
COMMITTED PROJECTS PROCEEDING TO PROJECT PLANNING STAGES (INCLUDING YUB REVIEW)		
Marsh Lake Fall/Winter Storage (2007) Capital cost: up to $1 million	Economic opportunity for "Supply Side Enhancement" to existing facilities.	• 1.6 MW of firm capacity toward criteria, plus • Hydro peaking capability, plus • 7.7 GW.h/year long-term energy. • Long term net diesel cost savings of $10.0 million (NPV, 2005$) under Base Case load forecasts.
Carmacks to Stewart Transmission Line Project (2008) Capital cost: $35 million funded by YTG as required to ensure no adverse rate impacts.	Expansion of WAF system to interconnect WAF and MD, and to link two mine projects to WAF hydro surplus. (YTG funding of capital cost to ensure no adverse rate impact).	• Enhance near term link for new mines to WAF hydro surplus. • No new MD supply to WAF unless connect WAF and MD systems. • Once connected, up to 6 MW of enhanced capacity for criteria, and up to 15 GW.h/year added hydro energy (decreasing over time).

[21] Table 4.2 is in 2005$. This table does not indicate the discounted present value of capital costs given in-service dates, the life of each option, or the rate-related impacts of depreciation, interest and return on equity.

[22] NPV long-term net diesel savings reflects ratepayer NPV diesel savings less NPV for capital and operating costs of the project. Present values are assessed over an assumed 65 year life based on the assumed in-service dates, a discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre (peaking) and 3.9 kW.h/litre (baseload), diesel fuel prices at $0.65/litres (2005$), diesel O&M at $0.016/kW.h (2005$) and inflation at 2%/yr. No firm capacity or secondary sales benefits are included. See Appendix C for NPV long-term net diesel savings for the Aishihik 3rd Turbine Project (without and with Marsh Lake Fall/Winter Storage).

The costs and time requirements for the identified "opportunity" projects vary significantly, and are material when assessing each option. Based on Table 4.2, the following summary observations are provided:

- **Marsh Lake Fall/Winter Storage**: The least costly option (up to $1 million estimated cost) and potentially fastest to implement option (potential in-service by fall 2007) is the Marsh Lake Fall/Winter Storage project, where the only major work required is to secure the relicencing as needed. Under these circumstances, it is readily apparent that, once developed, the project's economic benefits materially exceed its economic costs during the 20-year planning period as well as during the longer-term. Table 4.2 indicates long term net diesel savings of $10.0 million (NPV, 2005$) under Base Case loads.
- **Aishihik 3rd Turbine**: In contrast, even though the necessary licensing is in place, the Aishihik 3rd Turbine project requires both material costs (estimated currently at about $7 million) as well as material time to implement (earliest likely in-service may be 2008, but more reasonably scheduled for 2009). Under these circumstances, more detailed economic and financial assessments are needed to determine whether the project is likely to yield net economic benefits during the planning period (even though long term net benefits are likely to occur, based on assessments done in the past). Table 4.2 indicates long term net diesel savings of $4.1 million (NPV, 2005$) under Base Case loads.
- **Carmacks to Stewart Transmission Line**: This project will proceed only if Yukon Government funding ensures no adverse impact on ratepayers. Accordingly, costs are not a driver in its assessment in this Resource Plan, i.e., if developed under these terms, its costs will be required to be competitive with the least cost options then available to meet system requirements. The project is in the early project planning stages and at the earliest could be in service between mid-2008 and mid-2009.

More detailed assessment reviews are provided below of each project.

4.4.1.1 Aishihik 3rd Turbine Project

Under Base Case or higher loads without other sources of new hydro energy, the present value savings from displaced diesel for the Aishihik 3rd Turbine option are expected to offset fully its capital costs. Specific economic assessment cases are reviewed below (see Appendix C for more detailed tables setting out the economic and financial present value assessments by year over the 65 year assumed economic life of this project):

- **Base Case with no other projects:** Under Base Case conditions, assuming a 2009 in-service the present value (2005$) over the 20 year planning period of these diesel cost savings is approximately equal to the costs that would be imposed on ratepayers of the third turbine (depreciation, interest, return on equity, O&M) based on diesel prices at $0.65/litre (2005$); this present value is beneficial by $4.1 million over the 65 year life of the project[23].
  - This reflects a NPV of diesel fuel and O&M savings of $11.2 million (2005$, largely increasing throughout the period) and a NPV cost of the project (capital plus O&M) of $7.1 million.
  - It ignores benefits from increased ability to make secondary sales[24].
  - Under this scenario, the project would require 8 years from in-service until it was a net positive impact on annual rates (to 2017)[25].
  - The impact on YEC's revenue requirement in any given year over the 20 year planning period would vary from about negative $0.67 million (first year) to a savings of about $1.44 million (2022) without including any secondary sales benefits in the near term.

- **Base Case with Mines:** If Aishihik 3rd turbine is developed concurrently with about 10 MW of new mining load (the "base case with mines" scenario), the project net benefits over the 20 year planning period total $3.7 million (NPV, 2005$) and $7.9 million over the 65 year life of the 3rd turbine project. In this case, the project is a positive impact on revenue

[23] Assuming a nominal discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre for peaking and 3.9 kW.h/litre for baseload, diesel fuel prices at $0.65/litres (2005$), diesel variable O&M at $0.016/kW.h (2005$) and inflation at 2%/yr. Depreciation over 65 years is consistent with the "waterwheels, turbines and generation" category of assets as approved in the 2005 Required Revenues and Related Matters Application.

[24] Yukon Energy does not presently have sufficient load data to analyze the potential revenue benefits related to increased number of hours of secondary sales availability. In rough terms, winter secondary sales average at about 3 MW, or about $198/hour at the current 6.6 cents/kW.h rate effective January 2006 (the rate approved by the YUB in Order 2005-12 was 5.2 cents/kW.h, effective January 2005 with ongoing quarterly adjustment to reflect changes in hearing oil prices). The Aishihik 3rd turbine will reduce the number of hours of diesel generation required on the system by about 127 hours in 2009 (first year of in-service) to about 1004 in 2021. In practice, secondary sales are interrupted for much longer than actual diesel generation time, as these sales can be interrupted for 24-48 hours in advance of expected cold weather. Even at the 127-1004 hour range of actual diesel generation, added secondary revenues would approximate $25,000 to $199,000 per year over the period (prior to WAF requiring base load diesel, which would lead to a total secondary sales interruption year round).

[25] Were Marsh Lake Fall/Winter Storage developed separately in advance of the Aishihik 3rd turbine (in 2007), the NPV of the project under Base Case loads over 20 years would become negative $1.0 million, and positive $3.1 million over the life of the project (ignoring secondary sales benefits), with 9 years required from a 2009 in-service to net annual cost savings to ratepayers (by 2018). Under this scenario, and without further development of mine loads or additional load growth, a delay of 1-2 years may be advisable (decision to proceed in 2009 for in-service in 2011) which would reduce the number of years of adverse rate impact back to 7, with an NPV over the period to 2025 (reflecting only 15 years of project service to that time) of negative $0.3 million (lifetime NPV savings of $3.8 million, compared to $3.1 million if developed at 2009 after Marsh Lake, or $4.1 million if developed at 2009 with no Marsh Lake).

requirement by year 3, with the annual impact varying from negative $0.10 million (first year) to $1.44 million (2022)[26].

In summary, the Aishihik 3rd turbine project is an economically viable upgrade to the existing system that can be economically pursued in the near term. The project economics are enhanced to the degree that mine loads arise in the near term. The Resource Plan reflects commitment to this project for an in-service of 2009 (requiring major design and tendering, as well as a YEC Board of Directors decision to construct, to occur in late 2007/early 2008)[27]. Projects assessed in subsequent sections of this Chapter presume successful implementation of this project by fall 2009.

4.4.1.2 Marsh Lake Fall/Winter Storage Project:

The Marsh Lake Fall/Winter Storage project provides three sources of benefits:

1. **firm capacity** (1.6 MW towards both N-1 and LOLE),
2. **ability to avoid peaking diesel** (via extra 1.6 MW of hydro available at peak times before YEC must run diesels), and
3. **increase to long-term average energy** (7.7 GW.h but varies somewhat based on system loads).

As a source of new capacity alone, the expected costs of the project are not expected to be more than $1 million (primarily related to environmental licencing and mitigation works) and equate to $0.625 million/MW (compared to $0.8 to $0.9 million/MW for new diesel).

However, the capability to enhance the system with added peaking ability as well as added long-term average energy equally justifies the Marsh Lake project (at an expected net present value of $10.0 million in diesel savings to ratepayers (2005$) over the life of the project (at Base Case loads) with $1.9 million (2005$) of these savings occurring during the period of the Resource Plan to 2025).

[26] Were Marsh Lake Fall/Winter Storage developed separately in advance of the Aishihik 3rd turbine (in 2007) under the Base Case with Mines load forecast, the NPV of the Aishihik 3rd Turbine project over 20 years would become positive $2.6 million, and positive $6.7 million over the life of the project, with three years required from a 2009 in-service to net annual cost savings to ratepayers (by 2012). This assessment is not adversely affected if the Carmacks-Stewart Transmission Project is also developed in 2008 (see Appendix C).

[27] In the event that Marsh Lake Fall/Winter Storage is pursued, mine loads are not proceeding towards commitment, and WAF loads are below forecast through 2006 and 2007, it may become necessary to delay the decision to construct by one to two years or more, depending on load conditions and forecasts at that time, in order to minimize potential adverse rate impacts in the early years of the project.

Accordingly, the Resource Plan reflects commitment to proceeding to the licencing and detailed technical stages with this project for in-service by August 2007 or August 2008. Projects assessed in subsequent sections of this Chapter presume successful implementation of the Marsh Lake Fall/Winter storage project by August 2007.

4.4.1.3 Carmacks to Stewart Transmission Project:

This project is being examined using Yukon Government funding, on grounds separate from near term WAF capacity needs.

As Yukon Energy cannot independently justify the interconnection on any reasonable current economic grounds based on specific diesel savings or capacity benefits, the proposal to proceed with the project is solely linked to external factors related to Yukon Government funding and the development of the two mines. Accordingly, assessment of other project options in this Resource Plan does not presume development of this interconnection.

The portion of this project from Carmacks to at least Pelly Crossing is likely to be in place if and when the Minto and/or Carmacks Copper mines are supplied with WAF grid power[28]. Accordingly, if and when it becomes clear that these mine loads will develop for WAF, extension of this transmission project from Pelly Crossing to Stewart Crossing (to provide full interconnection of the MD and WAF grids) is likely in any event to be a technical option to provide WAF access to additional capacity (about 6 MW) and surplus hydro energy (about 15 GW.h).

- The cost effectiveness of this interconnection option will continue to depend on Yukon Government funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy.
- In this situation, assessments will need to consider the extent to which the surplus hydro made available under this load situation will yield WAF economic benefits during the planning period that serve to offset at least some of the capital costs through both diesel unit cost savings and extended maintenance of secondary sales revenues.
- Full assessment of this option will also need to address risks related to re-opening of the UKHM mine (or other new industrial developments) which would reduce or eliminate the MD surplus hydro, as well as potential new opportunities provided by the interconnection, such

[28] Together, these mines are currently expected to require between 9 and 11 MW of peak power, and up to about 60 GW.h/yr of energy. The added net peak load imposed on WAF by these mines will depend on the extent to which these new mining operations develop their own on-site diesel plants either for backup or other reasons (potentially including interim operation prior to the arrival of utility power, or for benefits associated with waste heat during certain seasonal operations).

as potential additional enhancements for the existing Mayo hydro facility (including enhanced peaking capability) or other new generation opportunities in the MD area.

4.4.2 Assessment of Capacity-Related Projects

With the adoption of new capacity planning criteria, major investments in the near term are required to adequately serve forecast WAF loads. This conclusion is consistent over a wide range of possible load forecast conditions, which indicate WAF capacity shortfalls beginning in 2006 and increasing to between 15 MW and 27 MW by 2012 for the current customer classes plus potential mining operations. In contrast, the MD system has no forecast capacity shortfalls by 2012 under the revised capacity planning criteria in the absence of new major industrial loads.

Based on assessment of the "opportunity" projects reviewed in Section 4.4.1 above, the Resource Plan assumes commitment to the Aishihik 3rd Turbine project for in-service at 2009 and to the Marsh Lake Fall/Winter Storage project for an in-service date of August 2007. Accordingly, these projects are assumed to be in-service at the noted dates for the purposes of assessing the requirement for capacity-related projects. However, because the proposal to proceed with the Carmacks to Stewart Transmission Line project is solely linked to external factors related to Yukon Government funding and the development of the two mines, assessment of capacity-related project options does not presume development of this interconnection. Accordingly, the possibility of the Carmacks to Stewart Transmission Line project (as an option) is included in the assessment of the capacity-related project options.

Table 4.3 summarizes the capital cost (2005$) estimates outlined in Section 4.3 for screening purposes related to the near term major resource options to address capacity shortfall requirements. These initial screening cost estimates assume additional diesel units as the default option to provide any remaining capacity needed beyond that provided by the major project option, as well as the opportunity projects presumed to be in place (Aishihik 3rd turbine at 2009 and Marsh Lake Fall/Winter Storage at 2007)[29].

[29] Capacity required over and above major project options are lower than noted in *Section 4.3 Options* due to the assumed in-service of Marsh Lake Fall/Winter Storage in 2007 and Aishihik 3rd turbine (where relevant) in 2009.

Table 4.3:
Comparison of Near Term Capacity-focused Options to 2012
Assuming Marsh Lake Fall/Winter Storage in 2007 and Aishihik 3rd Turbine in 2009
Without Carmacks to Stewart Transmission Project Interconnection of WAF and MD
(Capital costs (2005$ millions) - No present value assessments)

MAJOR PROJECT OPTIONS	**ADDITIONAL DIESEL REQUIREMENT BY 2012 and costs if met with new diesel capacity**[30]						**TOTAL COSTS TO 2012**
	Base Case Loads		***Low Sensitivity***		***High Sensitivity with Mines***[31]		
	Capacity	Cost	*Capacity*	*Cost*	*Capacity*	*Cost*	
Mirrlees Life Extension (14 MW; $3.0 to $4.5 million)	3.1 MW	$2.5 to $2.8 million	*0 MW (0.9 MW surplus)*	*$0*	*10.5 MW*	*$8.4 to $9.5 million*	**Base Case**: $5.5 - $7.3 million **Range**: $3.0 - $14 million
Whitehorse Diesel Replacement / Expansion (expected maximum of 33 MW[32])	17.1 MW	$13.7 to $15.4 million	*13.1 MW*	*$10.5 to $11.8 million*	*24.5 MW*	*$19.6 to $22.1 million*	**Base Case:** $13.7-$15.4 million **Range**: $10.5 - $22.1 million
Aishihik 2nd Transmission Line in 2009 (22 MW at N-1 and 14.4 MW at LOLE; $16.0 to $19.0 million)[33]	0 MW (4.1 MW surplus)	$0	*0 MW (8.1 MW surplus)*	*$0*	*10.1 MW*	*$8.1 to $9.1 million*	**Base Case**: $16.0 - $19.0 million **Range**: $16.0 - $28.1 million

[30] Costs to meet calculated shortfall in capacity, at $0.8-$0.9 million per MW (2005$) – assessment does not reflect optimization of unit size increments. Estimates assume Carmacks to Stewart Transmission is not developed (with development of this project, capacity shortfalls to be supplied by additional diesel would be reduced by about 5 to 6 MW in 2012).
[31] The Base Case with Mines capacity shortfalls in 2012 are 5.2 MW less than shown here for High Sensitivity with Mines.
[32] Capital costs at $0.8-$0.9 million per MW (2005$); 33 MW is expected to be possible at the existing Whitehorse Rapids diesel plant using 3 - 11 MW units. Beyond 33 MW, consideration is required of site options given limitations of existing building and site.
[33] If an Aishihik 2nd transmission line is constructed, the WAF system capacity requirements become driven by the LOLE criteria not the N-1. Consequently, although the Aishihik 2nd transmission line provides 22 MW load carrying capability under the N-1 criteria, and 14.4 MW under the LOLE criteria, the net effect of constructing the line under the Base Case conditions is 21.2 MW (from a 17.1 MW shortfall to a 4.1 MW surplus at 2012), reflecting that with the 2nd line the LOLE criteria rather than the N-1 criteria creates the ultimate capacity requirement.

Assessment of options to address near term requirements remains dependent upon ongoing investigations to define in more detail each option's conditions and costs. The major Resource Plan near term options to address capacity shortfalls are assessed below in light of current information and the revised capacity planning criteria requirements. The assessment is addressed under two main situations regarding the technical feasibility of the Mirrlees Life extension option, assuming that it will be determined within the next few months to be either feasible or not feasible.

4.4.2.1 Assuming Mirrlees Life Extension Project is Technically Feasible

If the Mirrlees Life Extension project is technically feasible, this is the clear least cost option to provide 14 MW of reliable near term capacity. At $3.5 to $4.5 million for all three units, this option costs from $250,000 to $321,000 per MW. These costs are well below those needed for diesel replacement/expansion (at $800,000 to $900,000 per MW), or the costs for an Aishihik 2nd transmission line. Mirrlees Life Extension can also be developed incrementally as needed.

Notwithstanding these obvious advantages, serious technical issues are still being addressed to determine if this option is feasible and capable of providing full life extension of 10-20 years (including all required parts and technical support from the manufacturer). It is expected that an initial decision will be made in first quarter of 2006 based on an assessment of the capability of the manufacturer to provide technical resources and support, references of other utilities who have pursued life extension options with similar Mirrlees units, and refined expected costs of the option based on further assessment of both overhaul requirements and shared facility requirements (which are ongoing).

If the Mirrlees Life Extension option is determined to be feasible and acceptable on technical grounds, a series of steps and assessments will remain to address the expected near term capacity shortfalls and other near term resource development opportunities. These assessments are set out below:

1. **Proceed with initial Mirrlees 5 MW Unit Life Extension project in 2007**: The first step will involve Yukon Energy contracting out a first "teardown" level of overhaul on one of the units to occur during the summer of 2007 (focusing likely on the 5 MW unit to be retired currently in 2007). The common diesel plant upgrade work would also be undertaken at the same time (at an estimate cost of $1.0 to $1.5 million). Yukon Energy is proposing this schedule in light of the current expectation that the maximum cost commitment for this first unit would not exceed $2.5 million (2005$). Under this scenario, the WAF system would experience an expected capacity shortfall during the winter of 2006/07 of about 0.7 MW prior to the planned capacity work in 2007.

2. **Proceed with the other two Mirrlees unit Life Extensions in 2008 and 2009**: The other two unit Life Extension projects would be proceeded with on a timely basis. Prior to proceeding with each of these projects, which are currently expected to cost up to $1.0 million (2005$) per unit, Yukon Energy would review the experience gained from Life Extensions carried out to date.

3. **Preferred Options to meet the Remaining Capacity Shortfall on WAF (3.1 to 10.5 MW)**: Even with provision of 14 MW from the Mirrlees Life Extension project, Yukon Energy will still need under the Base Case load conditions to develop at least an additional 3.1 MW new capacity by 2012 (and this added requirement could range up to 10.5 MW under the high load cases examined). Adoption of the Life Extension option will affect the assessment of the other remaining options to provide the balance of the capacity requirement (based on the assessments below, the Carmacks to Stewart Transmission Line Project, if developed with Yukon Government funding, could provide a preferred way to provide up to about 6 MW of added firm capacity):
   a) **Whitehorse Diesel Expansion options would be limited - may need to assess other locations for additional diesel unit units as a default option:** The option of developing Whitehorse Diesel Expansion might not be feasible within the current building or even potentially at the current plant site under these conditions, and it may be necessary to assess other locations for any additional diesel unit options. Costs for diesel expansion at a new location as a default planning option involving 4 MW or larger units are likely to approximate $1 million per MW. A variation that may merit consideration is Life Extension on the two larger (5 MW nameplate) Mirrlees units, plus replacement of the smaller Mirrlees unit (4 MW nameplate) with an 8 or 11 MW new unit to secure the needed capacity.
   b) **2nd Aishihik Transmission Line not likely to be cost effective option:** The Aishihik 2nd Transmission Line project by itself is not likely to be cost effective in the near term under these conditions, given its cost (currently estimated at $16 to $19 million) and its “lumpy” delivery of 22 MW of effective capacity all at one time.
   c) **Carmacks to Stewart Transmission Line can be attractive with Minto and Carmacks Copper Mine Loads:** The portion of this project from Carmacks to at least Pelly Crossing is likely to be in place if and when these mines are connected to the WAF grid. Accordingly, if and when it becomes clear that these mine loads will develop for WAF, extension of this transmission project from Pelly Crossing to Stewart Crossing (to provide full interconnection of the MD and WAF grids) is likely in any event to be a

technical option to provide WAF access to additional capacity (about 6 MW) and surplus hydro energy (about 15 GW.h); the cost effectiveness of this option may also be resolved based on Yukon Government funding to ensure no adverse effect on ratepayers relative to any other option. (See Section 4.4.1.3 for further review of this option. [34])

4.4.2.2 Assuming Mirrlees Life Extension is Not Technically Feasible

If the Mirrlees Life Extension project is not technically feasible and the Mirrlees units must be retired, the key initial decision becomes whether or not to develop the Aishihik 2nd Transmission Line Project. As noted in Table 4.3, the Aishihik 2nd Transmission Line fully addresses the capacity requirements of the Base Case loads.

In summary the near term choice under these conditions is between the Aishihik 2nd Transmission Line Project (22 MW of near term capacity benefits under N-1, 14.4 MW under LOLE)[35], versus reliance on major Whitehorse Diesel Replacement/ Expansion for at least the same amount of new near term capacity (17.1 MW, with potential to range from 13.1 MW to 24.5 MW). As reviewed below, current information does not necessarily indicate a clear preferred approach under these conditions. Ongoing investigations will continue to assess these options if it becomes clear that the Mirrlees Life Extension option is not technically feasible.

Technical, cost and risk issues assessed with regard to this choice (see below) underline the nature of the problems and opportunities associated with selecting the Aishihik 2nd Transmission Line option at this time rather than pursuing Whitehorse Diesel Replacement/Expansion on an incremental basis in the event that the Mirrlees Life Extension is not feasible:

1. **Cost effectiveness of capacity benefits for Aishihik 2nd Transmission Line option is affected by several factors**: Initial review of capital costs per MW indicates that the Aishihik Transmission Line option is likely to cost from $0.73 to $0.86 million per MW (2005$) under the N-1 condition (from $16 to $19 million, to provide 22 MW) or from $1.11 to $1.32 million per MW (2005$) under the LOLE condition (for 14.4 MW firm load carrying capability).

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[34] Assuming Mirrlees Life Extension is implemented, the Carmacks to Stewart Transmission Line would displace up to about 6 MW (depending on the load case assumed) of new diesel expansion capacity costing about $1 million per MW (2005$).

[35] Given that the Aishihik 3rd Turbine is economic on its own for energy-related reasons in the near-term, the benefits of the Aishihik 2nd Transmission line are 22 MW under N-1 (i.e., if Aishihik 3rd Turbine is already built prior to the line, the line would serve to reduce the "N-1" factor from 37 MW (the total capacity output of Aishihik) to 15 MW (the largest single wheel at Aishihik).

2. The cost effectiveness of this option is affected by several factors:
   - Transmission Line Capital Cost is lower than comparable Diesel Replacement/Expansion Capital Cost under non-industrial scenarios: This transmission project capital cost under N-1 is estimated to be slightly lower than the capital cost (2005$) expected for Whitehorse Diesel Replacement/Expansion ($0.8 to $0.9 million per MW). This however ignores the addition risks related to transmission line cost estimating compared to new diesels, as set out below.
   - Transmission Line Capital Cost is higher than diesel if LOLE criteria applies with sufficient mine development: The cost competitiveness of the Aishihik 2nd Transmission Line option is eroded in the event that mine development is sufficient to reduce its effective capacity contribution to only 14.4 MW (in the event that the LOLE criteria becomes dominant over the N-1 criteria).
   - Added Offset benefits possible from Aishihik 2nd Transmission Line if develop future Aishihik capacity via re-runnering: The Aishihik 2nd transmission line enables the opportunity for other potential capacity-related projects at Aishihik (as yet relatively undefined) focused principally on re-runnering the existing units for added capacity output of potentially up to 6 MW. Although this potential future project has not been costed or had sufficient technical or environmental analysis (such as flow velocities), re-runnering is often viewed in other jurisdictions as a cost-effective way to enhance the existing system for added capacity (and/or energy). Without the Aishihik 2nd Transmission Line project, it is unlikely that rerunnering at Aishihik would be economic (sicne it would not provide any effective ability to contribute to firm WAF capacity during the winter peak).

3. **Timing and Cost Risk Concerns with Aishihik 2nd Transmission Line options:** Key concerns with regard to the Aishihik 2nd Transmission Line Project include the timing and substantial costs needed to deal with planning, permitting, and approvals prior to receiving solid capital cost estimates via the tendering process. If a preliminary commitment to the project was in place in 2006, planning and firm cost estimates would not likely be completed until well into 2007 at the earliest and the transmission line's in-service would in all likelihood be no earlier than 2009. During the period to 2009, capacity shortfalls on the WAF system would grow to 7.1 MW (related to both load growth and retirement of the first Mirrlees WD3). On these matters (timing, and the delayed certainty with respect to cost estimates, and the risks of capacity shortfalls in the interim) the Whitehorse Diesel Replacement/Expansion option is expected to have a clear advantage.

4. **Load Risk Concerns with Aishihik 2nd Transmission Line options:** The potential cost effectiveness of the Aishihik 2nd Transmission Line combined with the Aishihik 3rd Turbine project is dependent on load conditions. This is because the project provides more capacity than is required at 2012 under the Base Case and Low Sensitivity scenarios, but is of lesser capacity value under the very high sensitivity case scenarios with mines (14.4 MW, compared to 22 MW under N-1) which clearly exceed Base Case forecasts[36] while also not becoming so high due to new industrial mine loads as to cut back the effective capacity benefits[37].

5. **Issues regarding 2nd Transmission Line Overlap with Carmacks to Stewart Project:** Concurrent development of the Carmacks to Stewart Transmission Line project with the Aishihik 2nd Transmission Line Project could create adverse overlap issues for Yukon Energy with regard to planning, permitting, design and construction if the Carmacks to Stewart project is proceeding as reviewed in 4.4.1. Conversely, in the even of the Base Case with Mines loads, the two project could together meet the overall capacity shortfall by 2012[38].

6. **Carmacks to Stewart Transmission Line can be attractive with Minto and Carmacks Copper Mine Loads:** The portion of this project from Carmacks to at least Pelly Crossing is likely to be in place if and when these mines are connected to the WAF grid. Accordingly, if and when it becomes clear that these mine loads will develop for WAF, extension of this transmission project from Pelly Crossing to Stewart Crossing (to provide full interconnection of the MD and WAF grids) is likely in any event to be a technical option to provide WAF access to additional capacity (about 6 MW) and surplus hydro energy (about 15 GW.h); the cost effectiveness of this option may also be resolved based on Yukon Government funding to ensure no adverse effect on ratepayers relative to any other option. (See Section 4.4.1.3 for further review of this option.)[39].

[36] This option is clearly not cost effective even when assessed over 40 years to 2045 under the Low Sensitivity case. Even under Base Case loads, securing 40-year net present value benefits can be very sensitive to assumed costs and diesel saving magnitudes.

[37] Net benefits over 40 years, for example, will be minimal under some cost and diesel saving assumptions at 25 MW mine loads.

[38] Under such joint development without Mirrlees Life Extension, the Carmacks to Stewart Transmission would displace about 5 MW of new diesel costing about $0.8 to $0.9 million per MW (2005$).

[39] Regardless of the selection of Aishihik 2nd Transmission project or Diesel Replacement/Expansion (assuming Mirrlees Life Extension is not implemented), in the event that the Minto and Carmacks Copper mines are developed the Carmacks to Stewart Transmission Project would appear likely to displace by 2012 up to about 6 MW of new diesel costing $0.8 to $0.9 million per MW.

4.4.3 Schedule and Sequencing of Alternatives

Based on the review of opportunity and capacity-related projects above, the potential scheduling and sequencing of these near term projects is illustrated in Figure 4.15.

As indicated in Figure 4.15, both opportunity projects and capacity-related projects are required to be initiated and pursued in the near term to address constraints (Marsh Lake Fall/Winter Storage and Capacity-Related projects to address capacity shortfalls; Carmacks-Stewart Transmission Line to address opportunity to service mines in the region, as well as access YTG infrastructure funding).

The exception to current timing constraints is the Aishihik 3rd turbine. This project has some flexibility regarding the scheduling and in-service date (as it does not contribute to firm capacity shortfalls). As indicated in Appendix C, the economics of the project are considerably improved if it is in service as of the start of any new mining loads. However, without new industrial loads and with Marsh Lake Fall/Winter Storage proceeding, it may be advantageous to delay Aishihik 3rd turbine by about two years compared to the timing in Figure 4.15; this decision can be part of the late 2007 assessment by YEC as to whether to proceed with the project at that time.

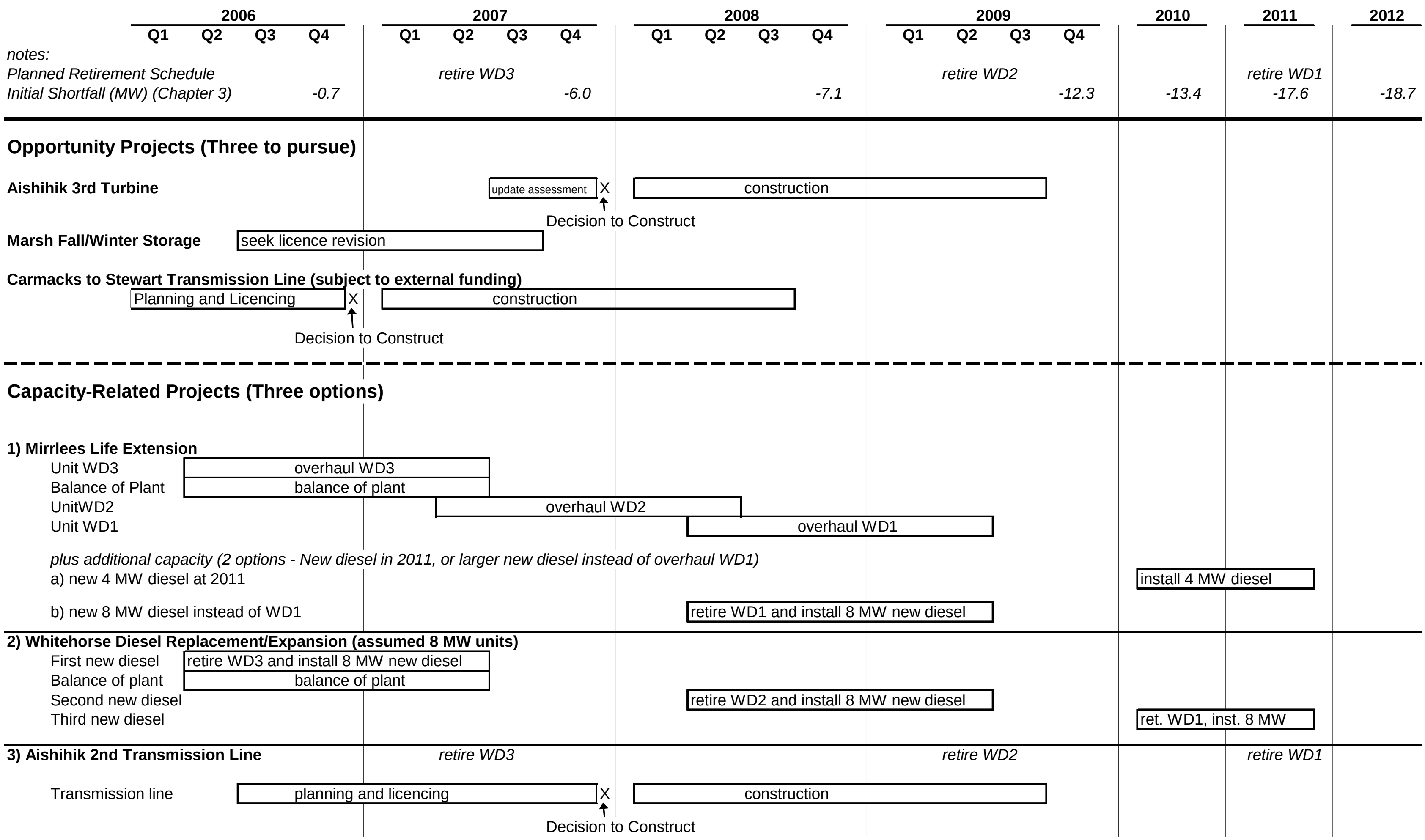
4.4.4 Rate related Impacts of Near Term Options

This section provides a brief examination of the expected effects of preferred near term projects on overall utility costs and rates.

Separate financial assessment is required of the effect of any project on rates, as rates for any given year are set based on annual costs (including depreciation, interest and return on equity) rather than the lifetime long-term costs of projects in service. For capital intensive projects such as hydro or transmission, these annual costs tend to be at a maximum in the first few years of the project (when rate base balances are highest) while benefits can in many cases extend and grow many years into the future (50-100 years in some cases).

Under current rates and OIC 1995/90, Yukon-wide rate impacts are likely to arise of about 1% if utility costs (revenue requirements) are increased in any one year by $360,000 compared to alternatives.

Figure 4.15:
Timing and Sequencing of Opportunity and Capacity-Related Projects



Two key aspects of rate impacts arise with respect to the near term projects:

1. **Opportunity Projects seek to put in place economic assets that provide long-term benefits:** The relative rate impacts of the three opportunity projects vary depending on the particulars of the project:
   a) **Aishihik 3rd turbine:** As reviewed in *section 4.4.1*, the Aishihik 3rd turbine project provides long-term rate benefits. In the first years of the project, however, there is the potential for adverse rate impacts (see Appendix C for more detailed tables):
      i. **Base Case Assumptions:**, Under Base Case assumptions, much like other capital intensive hydro projects, the annual costs of the project will outweigh the annual benefits for a number of years (until offset by inflation and load growth). At a maximum (year 1 if developed in 2009) this impact will be less than 2%, which declines through 2017 (2018 if develop Marsh Lake Fall/Winter Storage first) after which it becomes a positive and growing rate benefit.
      ii. **Base Case with Mines:** If about 10 MW of new industrial loads are connected to the system in the near term (consistent with the two mines now proposed north of Carmacks), the maximum adverse rate impact (year 1 if developed in 2009) will be 0.3% (0.9% if Marsh Lake Fall/Winter Storage previously developed), and by year 3 will be a positive and growing rate benefit compared to the situation without the project (year 4 if Marsh Lake Fall/Winter Storage previously developed).

      In this case, some benefits of the capital intensive Aishihik 3rd turbine increase each year as the value of diesel displaced increases with inflation or other upward fuel price drivers. However, the Aishihik 3rd turbine project imposes the highest costs on ratepayers in the early years.

      In summary, although very attractive economically over the long-term, the Aishihik 3rd turbine project will result in adverse rate impacts in the first year of the project under all near term cases assessed (0.3% to almost 2%), with this impact lasting 2-8 years (this is similar to the MD Transmission Project, which was forecast to be a beneficial project for ratepayers over its life, but did result in the need to address what would otherwise have been adverse rate impacts in the first two years via flexible debt financing from YDC).
   b) **Marsh Lake Fall/Winter Storage:** This project brings firm capacity, peaking capacity and long-term energy benefits. The costs of the project (estimated at no more than $1 million) reflect a maximum cost for the firm capacity of $0.625 million/MW, which is

cheaper than new diesel (assuming all capital costs of the Marsh Lake project are calculated in the cost/MW, ignoring energy benefits). Ignoring energy benefits, the capital-related costs of Marsh Lake at the maximum $1 million level would drive annual depreciation costs of $0.016 million plus interest and return on equity costs in the first year of about $0.078 million plus O&M costs of about $0.005 million. At a maximum, the project will be an upward rate driver of about 0.28%, offset by the savings in peaking diesel (which exceed this level by 2013).

c) **Carmacks-Stewart interconnection:** This project will only be developed if funded via no-cost capital (e.g., Yukon government funding) to a level that ensures no adverse rate impacts on ratepayers. The value of a potential Carmacks-Stewart interconnection will erode over time if the surplus hydro energy and installed capacity available for exchange between the two grids from this project reduce over time with load growth (or new industrial loads) on either system (as will occur at some point if load growth continues without development of new lower cost capital intensive energy resources). However, this limit only occurs to the extent that the flexibility provided by the interconnection does not enable development of attractive new generation projects (such as facility enhancements at the existing Mayo plant or other hydro opportunities in the MD area).

2. **Cannot avoid investment in new capacity, which will tend to be upward rate driver:** The adoption of the revised capacity planning criteria requires that under Base Case load assumptions a material investment in new capital spending will be required by 2012 assuming Mirrlees life extension is implemented, and higher investment if other alternatives are pursued. This amount is over and above normal utility capital amounts for re-investment and facility renewal (which tend to have a relatively stable impact on rates). The major new capacity-driven capital spending to 2012 results in relatively little change to other utility costs. The resulting rough estimations of gross impacts on rates at 2012 are as follows for the screening options noted in Table 4.3[40]:

   a) **Mirrlees Life Extension:** With a $5.5 million to $7.3 million capital investment by 2012 (2005$), resulting revenue requirements are likely to be increased by about $0.6 million to $0.8 million (at about 30 years depreciation on diesel assets and 7.52% average cost of capital) or in the range of 1.7% to 2.2% impact on rates.

[40] The calculations do not reflect estimated rate base values at 2012, which would be higher than simple capital cost estimates due to inflation between 2005$ and the actual date of in-service, and be reduced by depreciation from the date of in-service to 2012.

b) **Whitehorse Diesel Replacement/Expansion:** At an estimated Base Case requirement for $13.7 million to $15.4 million capital investment by 2012 (2005$), resulting revenue requirements are likely to be increased by about $1.5 million to $1.7 million (at 30 years depreciation on diesel assets and 7.52% average cost of capital) or in the range of 4.1% to 4.6% impact on rates.

c) **Aishihik 2nd transmission line:** Base Case costs of $16.0 million to $19.0 million (2005$) by 2012 (at 50 years depreciation for transmission line, 7.52% average cost of capital) with resulting annual costs of $1.5 million to $1.8 million, or rate impacts in the range of 4.2% to 5.0%.

The gross impacts noted above are full impacts to address capacity shortfalls to 2012 under the revised criteria. These gross impacts do not address the fact that major capital spending is required by 2012 even under the previous capacity planning criteria to address a shortfall of 5.6 MW under Base Case loads[41].

4.5 PROPOSED ACTIONS

Four separate major investments are proposed for Yukon Energy generation and transmission commitment before 2009, three with anticipated costs of $3 million or more. These proposed major projects will address near term requirements and opportunities to 2012 and together will provide over 21 MW of new WAF firm winter capacity by 2012 (i.e., enough new firm capacity to meet WAF capacity shortfalls that would otherwise be expected by 2012 of 18.7 MW under the Base Case forecast and 21.5 MW under the Base Case forecasts plus the Minto and Carmacks Copper mine loads). The four major proposed projects are reviewed below, along with contingency provisions and other proposed actions before 2012:

1. **Aishihik 3rd Turbine Project:** This project, which was initially reviewed in the 1992 YUB Resource Plan hearing, will provide 7 MW of added peaking capability[42] and about 5.4 GW.h/yr of long-term average hydro energy supply at the existing Aishihik generation station at a capital cost of about $7 million (2005$). Under Base Case loads without any new industrial developments, this project is expected to be economic within the planning period to

[41] If full Mirrlees Life Extension is pursued under Base Case loads under the previous criteria (to secure 14 MW of capacity by 2012, but worth 12.6 MW under the existing capacity planning criteria due to 10% diesel reserve factor, securing a 7.0 MW surplus and ensuring the units are not lost to disrepair and neglect), an estimated $3.0 to $4.5 million in capital costs would be expected to be incurred, for an annual rate impact cost of about $0.3 to $0.5 million or 0.9% to 1.4%.

[42] Without twinning of the Aishihik Transmission Line, none of this added Aishihik capacity is recognized under the N-1 WAF capacity planning criteria, and only 0.6 MW is recognized under the LOLE WAF capacity planning criteria.

2025 based solely on its diesel operating cost saving benefits for the WAF grid, including displacement of peaking and then baseload diesel as WAF loads increase. Yukon Territorial and environmental approvals for the project were received in the new Aishihik Water Licence.

a) Accordingly, this project will proceed with final planning activities to enable a final decision during 2007 to start construction for in-service by October 2009.

b) If Marsh Lake Fall/Winter Storage is developed without any additional non-industrial load growth or new industrial loads emerging, the final decision to start construction is proposed to be deferred until late 2009 for in-service in 2011 or 2012.

2. **Marsh Lake Fall/Winter Storage licence revision:** This project, which was not reviewed in the 1992 Resource Plan hearing, will increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and increase long-term average hydro energy from this facility by about 7.7 GW.h/year at a capital cost of no more than $1 million.[43] Yukon Energy will undertake the project planning activities, including consultation and environmental licensing, as required to seek amendment of the Whitehorse Rapids water licence to enable modified operation of Marsh Lake within its current lake levels to enhance fall/winter storage. Basically no new physical works are expected to be required for this project. Project approval is forecast by August 2007 (although provision is made in the event that the new Yukon environmental licencing regime requirements delays completion of the licence amendment to 2008). The effects of the proposed licence amendment are summarized as follows:

   a) **Remain within current lake level limits:** In all cases, the water levels with the amended licence will remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake).

   b) **Licence amendment changes the “controlled maximum” level:** The proposed amendment would change the licenced “controlled maximum” level that YEC can maintain upwards by about one foot; however, during uncontrolled periods of summer and fall (when YEC currently has no control over the lake and it is operating under an entirely natural regime), Marsh Lake has been known to peak at two feet above the YEC “controlled maximum” level. The effects of the proposed change are as follows depending on water conditions:

[43] This estimated capital cost is made up of the costs for licencing, any required mitigation works and any potential facility modifications

i. **Non flood year operation other than a drought:** This project would allow Yukon Energy to reduce the amount of water it releases in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period. No effect is to occur under these conditions in any year prior to August 15, other than under drought conditions (see below).

ii. **Flood year operation:** During flood years, there would be no change in the flood levels experienced on Marsh Lake, and no change to operations would be made during August and September until after flood levels subside.

iii. **During drought years:** Current licence provisions to help alleviate summer drought levels on Marsh Lake through “early closures” of the Lewes Dam would remain, and would likely be adapted to alleviate further summer drought conditions to ensure the lake reached the full supply capacity level in each year.

3. **Carmacks-Stewart Transmission Line Project:** This project will fully interconnect the MD and WAF grids as well as facilitate WAF transmission access to potential new mine loads at Minto and Carmacks Copper, providing 5.6 MW of additional firm near term capacity and 15 GW.h/year of additional near term energy for WAF[44]. Development of this project, which is estimated to cost about $35 million (2005$), is subject to provision of Yukon Government funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy. Based on external funding to assure no adverse impact on ratepayers from project development, planning activities will proceed with the Carmacks-Stewart project to enable a decision to proceed with construction early in 2007 for an in-service date in approximately late 2008.

4. **Mirrlees Life Extension Project:** Subject to confirmation of technical feasibility that is expected to be determined within the first quarter of 2006, the Mirrlees Life Extension Project will conclude final planning activities in 2006 in order to provide in-service during 2007 through to 2009 to provide an additional 14 MW of firm WAF capacity at a cost of up to $4.5 million (2005$).

[44] Added capacity and energy supplied to WAF by this interconnection are subject to MD loads, and will decline as MD loads increase. Reopening of the UKHM mine or other new industrial developments on MD, for example, would reduce MD surplus capacity and hydro energy available to WAF. In contrast, potential additional enhancements at the existing Mayo hydro facility or other new generation opportunities in the MD area could enhance overall WAF/MD power supply in the event of Carmacks-Stewart Transmission line development.

a) **First Mirrlees unit in service by October 2007:** By the summer of 2006 planning work and commitments for construction/implementation will begin on the first Mirrlees unit (5MW) at a cost of up to $2.5 million (2005$)[45] in order that in-service will occur before October 2007.

b) **Other two Mirrlees units by October 2008 and 2009**: Life Extension for the other two Mirrlees units will proceed thereafter for expected in-service in 2008 and 2009, subject to review of the experience gained from Life Extension of the first unit and the possible Yukon Energy consideration of replacing the third Mirrlees unit (4 MW) with a larger capacity new diesel unit (e.g., 8 MW or 11 MW unit).[46]

5. **If Mirrlees Life Extension is not technically feasible, implement diesel replacement/expansion and/or other project options as appropriate:** Without the Mirrlees Life Extension option providing 14 MW of firm capacity, the key near term choice is between the option involving Whitehorse Diesel Replacement/Expansion (capability for three units with combined capacity of up to at least 33 MW) versus the Aishihik 2nd Transmission Line (providing 22 MW under N-1 criteria and about 14.4 MW with LOLE criteria)[47].

Although the expected capacity shortfall can technically be met with the Aishihik-related option, this is not expected to be the lowest cost option to 2012 under Base Case loads and also this is not the lowest cost long-term option under higher loads including mines. The Aishihik-related option also exposes the WAF grid to near term and growing capacity shortfalls until it is completed.

Accordingly, the Diesel Replacement/Expansion option will be implemented as follows in the

[45] This cost includes a "teardown" level of overhaul and the common diesel plant upgrade work necessary to undertake the Mirrrlees Life Extension Project.

[46] In the event that Mirrlees Life Extension proceeds but the Carmacks-Stewart Transmission Line is not developed in the near term, replacing the third Mirrlees unit with an 11 MW new diesel would more than replace the capacity that otherwise would have been provided by the Carmacks-Stewart Transmission Project.

[47] In this context, the Aishihik-related option has been examined for possible implementation assuming that it is feasible to commit development of the Aishihik 2nd Transmission Line by 2009 at the latest; under this option, material near term capacity shortfalls would still occur until the Aishihik 2nd Transmission Line was in service.

event that Mirrlees Life Extension is not technically feasible[48]:

a) **First Diesel Unit (8 to 11 MW) needs to be installed by October 2007** Yukon Energy will need under these circumstances to proceed with final planning work on this project by summer 2006, including orders for the necessary engine unit (with cancellation provisions) in order that the unit can be installed by October 2007 at a capital cost (2005$) of up to about $7.2 million (8 MW) or $8.8 million (11 MW). This will include updating any common diesel plant systems necessary for connection of a new unit.

b) **Other Diesel Units**: Once the first unit is committed, it is expected that up to two additional diesel units (depending on the unit size selected) will be implemented thereafter as required for in-service before 2012.

6. **Ongoing monitoring of existing customer load forecasts and new industrial development opportunities:** In order to facilitate ongoing assessment of generation and transmission options and requirements, Yukon Energy monitoring of annual customer class load trends (peak capacity and seasonal energy) on each grid is required. In addition, Yukon Energy will continue to monitor directly with developers and government specific new industrial development opportunities for grid power service, including assessment of any mine site power contribution to the supply of reliable grid peak capacity.

7. **Other Small Enhancement Projects:** Continued routine utility investment is recommended in assessing and proceeding with projects to enhance existing facilities at a cost less than $3 million. This includes:
   - study of the hydrology of the Southern Lakes, and potentially pursuing small water control structures in this region (new generating stations to manage water plus generate hydro power would, if proposed in the future, exceed $3 million);
   - continued pursuit of opportunities to cost-effectively rewind or re-runner existing hydro generating units at Whitehorse and Aishihik; and,
   - assessing need and timing for a potential 1 MW diesel unit installation at Carcross/Tagish (likely by YECL).

[48] Diesel Replacement/Enhancement will also be the option pursued as required in the event that other major projects do not proceed as proposed, e.g., the Carmacks-Stewart Transmission Line Project (which is assumed to provide 5.6 MW by late 2008) and/or the Marsh Lake Fall/Winter Storage (which is assumed to provide 1.6 MW by fall 2007 or 2008). In the event that mine loads are connected to WAF without completion of the Carmacks-Stewart Transmission, Yukon Energy will review the feasibility of the Aishihik 2nd Transmission Line project.

5.0 INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

This chapter addresses planning activities that Yukon Energy may be required to carry out in order to be able to start construction on generation and transmission projects before 2016 (beyond those projects noted in Chapter 4 for commitment in the near term before 2009), largely to meet the needs of potential major industrial customers.

Industrial development scenarios and opportunities include possible new mines, or other major potential developments in Yukon including the Alaska Highway Natural Gas Pipeline project. This chapter focuses on project resource options that have the potential to meet the new capacity and energy needs associated with four potential industrial development scenarios (10 MW, 25 MW and 40 MW industrial development scenarios, and the Alaska Highway Pipeline).

The sections for this chapter are as follows:

- Section 5.1: Planning Approach and Timeline
- Section 5.2: Requirements
- Section 5.3: Options
- Section 5.4: Pre-Assessment and Screening
- Section 5.5: Proposed Actions

5.1 PLANNING APPROACH AND TIMELINE

Planning activities to proceed with other generation or transmission projects beyond 2009 and before 2016 are being driven by the potential needs of a diverse range of possible major industrial developments and the possible energy requirements and/or opportunities related to such developments[1].

Chapter 4 has shown that new near term industrial loads of up to 10 MW within the 20 year planning period typically give rise to capacity-focused resource options[2]. In contrast, new industrial loads above 10 MW within the 20 year planning period may create opportunities for energy-focused resource projects.

[1] Section 4.2.4 shows, under Base Case loads (without new industrial loads), WAF diesel generation remains below 10 GW/h/year until after 2020, and increases only to 28 GW.h/year in 2025. Near term development of the Aishihik 3rd Turbine and Marsh Lake Storage as proposed in Chapter 4 would reduce this Base Case WAF diesel generation, e.g., to about 15 GW.h/year in 2025.

[2] Near term WAF industrial loads of up to about 10 MW could increase this Base Case WAF diesel generation to about 40 GW.h by about 2016 (with development of Aishihik 3rd Turbine and Marsh Lake Storage as proposed in Chapter 4, this WAF diesel generation would be about 25 GW.h/year in 2016); however, in Section 4.2.6 such new near term mine loads are not expected to be sustained beyond about 10 years (i.e., beyond about 2017 if mine developments occur in 2007/2008).

Chapter 5 examines these energy opportunities in the context of the different possible load situations outlined in Chapter 1 (Figure 1.2), the significant uncertainties associated with such load possibilities, and the lead times and other needs associated with Yukon Energy protecting appropriate resource options related to these different possible loads.

The planning approach in this Chapter parallels that used in Chapter 4; namely:

1. **System capability** (part of *Section 5.2: Requirements*) over the intended 20-year horizon as well as to 2045 is reviewed.
2. **System requirements** (part of *Section 5.2: Requirements*) are reviewed over the 20-year plan horizon and to 2045, focusing on key characteristics for each of the four representative industrial load scenarios.
3. **Forecast New Facilities Requirements** (part of *Section 5.2: Requirements*) are reviewed over the 20 year planning term and implications to 2045, focusing on opportunities to develop new capital intensive energy projects with potential to displace future diesel-fuel generation required under each industrial load scenario.
4. **Resource Options** (*Section 5.3: Options*) to meet energy requirements under each industrial load scenario are identified and summarized to the extent that representative non-diesel generation resource projects can be defined today.
5. **Assessment of Options** (*Section 5.4: Pre-Assessment and Screening*): given the limited degree of information available today on most resource options, preliminary pre-assessment and screening of the identified options focuses primarily on "technical" considerations (how well various project sizes and location fit each scenario's potential load requirements). Where available, screening also considers to a limited degree "economic pre-assessment" of these options based on available information about the likely Levelized Cost of Energy or "LCOE" of each generation component.

This chapter sets out the actions that Yukon Energy proposes to take during the planning period to prepare for potential industrial development scenarios and opportunities beyond the near term, and to protect future opportunities to develop generation and transmission in a timely but cost-effective way. The planning activities proposed in this chapter are intended to strike a balance between the opportunities and risks associated with bulk power resource options selected to supply future Yukon industrial development.

5.1.1 Need to Consider and Balance Several Key Factors

Yukon and other experience in Northern Canada dramatically demonstrate how past industrial developments provided the opportunity to develop new generation and transmission infrastructure in a cost effective way, and how that infrastructure continues to yield sustained lower cost energy benefits to local residential and commercial power users long after the initiating industry has been closed[3].

The existing hydro at Aishihik and Mayo and the 4th wheel at Whitehorse were all linked directly with industrial developments which are now closed, as were the major hydro developments at Snare, Bluefish and Taltson in NWT (developed to service either mines that are now closed, or in the process of closing). Only areas in Northern Canada that have had industrial customer mining load have the benefits today of access to significant low-cost hydro.

Yukon and other Northern Canada experience also demonstrates that power resource planning regarding specific industrial developments can involve long pre-development timelines as well as considerable uncertainty and risk.

Accordingly, Yukon Energy needs to maintain a balanced approach to planning for grid power service to major new industrial loads. In particular, the approach must ensure that Yukon Energy is sufficiently prepared so as to “protect” feasible options to proceed with its own desirable resource projects quickly as needed should new industrial loads develop, while at the same time not spending more than is prudent to protect and advance such resource projects by, for example, proceeding to detailed feasibility stages based on mere load speculation or industrial development scenarios that are highly uncertain. Overall, this balance must be struck between two basic considerations:

a) **Readiness and Timing in relation to supplying new loads:** Due to industrial development planning and construction constraints, there may be limited time after a development’s load uncertainties are resolved for Yukon Energy to proceed with the new generation and transmission needed to supply a new industrial load development with grid-based power. In particular, planning, designing, licencing and constructing new generation or transmission can, in many cases, take at least as long if not longer than similar planning, commitment and construction for a new industrial development such as a mine. If not

[3] Section 2.1.1 in Chapter 2 reviews how today’s hydro generation and transmission facilities, developed in the past often in response to specific industrial mine-related load opportunities, are the key factor causing Yukon power costs today to typically be lower than those found in Alaska or the NWT.

sufficiently prepared and ready, new grid-based power service opportunities will be missed, likely in favour of on-site generation by the industrial customer. The potential significance of each such opportunity to Yukon's power system in the near and long-term merits careful consideration, along with assessment of the requirements to be sufficiently prepared and ready.

b) **Costs, timelines and Risks for resource project planning:** The planning phases for new generation or transmission can be costly and require many years of work prior to Yukon Energy being in any position to undertake final commitments to proceed with construction (with corresponding risks that potentially substantial spending on planning studies will indicate a project is not feasible). Understanding the likely costs, timelines, and risks associated with planning specific power resource options is an important precondition to assessing the likely requirements to be sufficiently prepared and ready.

As noted, when considering grid-based power supply options to new industrial loads, the key factors to be balanced in this regard relate both to the industrial development under consideration and to Yukon Energy:

- **Industrial Development factors**: Considerable uncertainty often persists as to timing and prospects to start and complete construction for a major new industrial development; even after successfully developed, material risks and uncertainties can remain as to the length of time for ongoing operation as well as the ability to meet ongoing financial obligations. Key factors in this regard include:
  - **Non-power uncertainty and risk factors:** In general, the key planning considerations and uncertainties for specific industrial developments derive from market, resource or other factors not related to power supply. Although power can be a cost factor that needs to be considered by potential industrial operations, such as mines or pipelines, it is often just one factor among many key considerations (such as financing, markets, licencing, or facility design).
  - **On-site power considerations:** Many major industrial developments if needed can rely upon on-site diesel generation or even (in some instances) their own fuel resource supply (e.g., coal for a coal mine, wood waste for a pulp mill, or natural gas for a natural gas pipeline) and will if required proceed without waiting upon development of access to utility grid-based power supply. In some instances, on-site generation may even provide opportunities to utilize waste heat or waste resources that can be used to supply energy; on-site generation capability may also provide critical requirements during construction or be needed as reliable backup to grid power during operation.

on-site generation capability may also provide critical requirements during construction or be needed as reliable backup to grid power during operation.

- **Short operating life and/or small scale power need:** In instances where a short operating life of (say) five to ten years is expected or at risk, or where the scale of the development involves relatively small power requirements, the incentive to incur material up front capital costs for connection to grid-based power may be severely reduced.
- **Cases where access to grid power is critical:** In some special cases, the feasibility of a specific industrial development may also be critically dependent upon access to grid-based power that is supplied at costs materially less than diesel fuel generation. In such instances, joint planning with the utility will be a key consideration to the industrial development's ability to proceed.

- **Yukon Energy factors**: Yukon Energy can also face a range of its own specific uncertainties and risks related to supplying grid power to major industrial developments. Key factors in this regard include;
  - **Inability to select or "forecast" in advance which industrial development scenario will unfold**: Based on current information, Yukon Energy cannot select or "forecast" in advance on any reliable basis (sufficient, for example, to commit material planning resources on any prudent basis) what level or scope or type of major industrial development is likely to occur by any specific time period under review in this Resource Plan.
  - **Limited value to current information**: Until uncertainties are resolved for a specific industrial development, it is typically also not practical or cost effective based on currently available information (regarding both the industrial development and the power resource options to supply its needs) to plan and assess in any detail how Yukon Energy may serve that development. If and when a development proceeds, its specific energy, power capacity and timing requirements (and the costs and needs for resource options to supply such requirements) in many cases are likely to vary significantly from current estimates.
  - **Limited time to respond to a new development once its major uncertainties are resolved:** As noted above, Yukon Energy will typically have only a very limited time to respond after uncertainties are resolved for a new industrial development before it becomes necessary to undertake power supply commitments; in many instances, as noted above, an industrial development will also simply proceed to use on-site diesel generation if Yukon Energy cannot commit on a timely basis to supply grid-based power.

– **Costs and time to develop new bulk power supply resources:** Yukon Energy may need to develop at least some new bulk power resources to supply grid power in response to a new industrial development. Opportunities to supply grid power that are contingent on planning, permitting and developing material new transmission and/or capital intensive non-diesel fuel generation resources are likely to require many years of work involving major capital costs prior to Yukon Energy even being in a position to make final commitments to proceed with construction of the needed resource projects – and capital intensive construction projects may then require several additional years (and cost risks) before coming into service.

– **Need to assess, and secure YUB approval of, ongoing rates:** Yukon Energy needs also to examine in advance the likely ongoing rate implications and risks, both for the potential industrial customer and for other Yukon ratepayers, and to secure YUB approval of any rate to be charged with regard to commitments to supply any new "major industrial customer" (as defined in OIC 1995/90).

– **No market value to power if developed but not needed in Yukon:** Unlike many southern jurisdictions with export connections, Yukon Energy cannot secure any economic value from projects except from sales to customers in Yukon, due to the lack of grid interconnections with external markets. In this regard, there is considerably more risk today to developing capital intensive bulk power projects in Yukon than in, say, Manitoba or British Columbia. This is because failure of local loads to develop as planned in Manitoba or BC can be offset by the opportunity to sell more power on export markets than otherwise would be the case. In contrast, once Yukon commits to a major capital intensive resource supply project, if the load does not develop or remain as planned the resource project has the potential to have zero or very limited value[4].

– **Resource Projects of a scale at or beyond Yukon Energy's current capability:** In some industrial development scenarios examined in this Resource Plan, the magnitude of required new generation and transmission opportunities may be at or beyond the current capability of Yukon Energy, or other Yukon entities, to finance and construct. For example, Yukon Energy presently has about $57 million in equity, while some of the

[4] This exact situation occurred with the construction of Whitehorse unit #4 in the 1980s. This unit basically provides almost exclusively summer energy, which was only of value at that time if the Faro mine was operating. However during construction of unit #4 the Faro mine closed, such that at the time of commissioning, the unit provided no economic value to the system. Since that time, substantial periods of operation of the Faro mine have provided opportunities to capture good economic value from unit #4. However, had the mine shut for good in the 1980s, unit #4 may have not been of any material value to the WAF system for decades after it was commissioned. Today, limited quantities of surplus hydro can be sold at lower secondary rates, however the potential is somewhat limited and is of lower value that full firm energy sales.

resource options considered in this Chapter approach $500 million to $600 million capital costs for generation alone (plus amounts for substantial transmission upgrades), and would involve the need to assess financial approaches and partnerships, potentially including participation by the Governments of Yukon and Canada. Such additional complications would likely increase planning timeframes and would also likely involve assessing options regarding sharing of risks associated with the projects.

5.1.2 Regulatory and Policy Framework

As a regulated utility, Yukon Energy's planning and developments occur within a regulatory and policy framework relating to its power supply developments and regulated rates charged to recover utility costs of service.

Where new industrial customers are located within areas presently served by Yukon Energy grid power, Yukon Energy must take into consideration its typical utility "obligation to serve" new loads that request electrical service. In contrast, Yukon Energy is not automatically required to serve new industrial loads that are located far away from the current Yukon grids unless the customer (or government) is prepared to fund directly the transmission costs and risks required for Yukon Energy to connect the new load to the grid[5]. In this regard, it is broadly assumed that major new industrial customers located materially away from the current grids would not be added to the Yukon grid systems due primarily to the constraints of incremental transmission connection costs. Without such connections, it is also assumed that a new major industrial load would typically be supplied by isolated on-site diesel generation with all costs being excluded from YUB consideration for the purpose of Yukon wide regulated rate setting (in accordance with OIC 1995/90).

The existing WAF system today can provide substantial (approximately 90 GW.h/year under normal water flows) attractive low-cost surplus hydro power to new industrial customers. The clear implication is that new industrial customers in reasonable proximity to WAF currently have major opportunities to secure material cost savings by purchasing WAF power supplies rather than using on-site diesel generation. Securing new industrial customers on WAF to allow sale of this surplus power at firm rates will also be a beneficial rate driver for all existing Yukon Energy and YECL firm customers, not only on WAF but throughout Yukon (due to the rate directive provisions of OIC 1995/90 which in effect integrate all utility

[5] As with new connection to WAF or MD by new non-industrial customers, transmission or distribution costs driven by new industrial customers are assumed to be funded by the industrial customer themselves (or by government), except to the extent that there is a cost effective case for Yukon Energy to invest in hooking up new industrial customers at a benefit to current ratepayers (pursuant to principles established in the Electric Service Regulations).

costs to equalize retail customer class rates through Yukon)[6].

However, the current WAF hydro power surplus is being reduced by ongoing normal growth in non-industrial customer firm loads, such that Secondary Energy sales on WAF that rely on surplus hydro power are expected to be fully curtailed by 2023 under the Base Case load forecast reviewed in Chapter 4 (see Figure 4.2).

Larger or longer-term new industrial power loads connected to WAF or MD that require energy materially beyond available surplus hydro power would, absent the development of new power resource options, drive major new diesel generation on these grids. Accordingly, Yukon Energy needs to identify and consider carefully the options and impacts to service such new industrial developments. For example, it may not be sensible 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. New grid extensions will similarly have limited long term value to the extent that they end up being used to transmit diesel generated power rather than hydro or other lower cost based power. Overall, looking at longer-term implications, such new industrial loads are likely to be attractive economically to the existing grid system only if they allow development of new capital intensive low-cost generation, such as occurred with the original opportunities to develop Mayo or Aishihik.

Accordingly, for new bulk power projects that may be developed in response to industrial development opportunities, Yukon Energy needs to assess the economics of the project (including attendant risks), the potential rate impacts on other utility customers as well as for the new industrial customer, and overall Yukon policy objectives.

On the matter of overall policy objectives, in other jurisdictions various broad policy objectives regarding resource development guide electrical system expansions[7]. In Yukon, the traditional energy policy

[6] Up to 30 GW.h of this surplus hydro may currently be sold to secondary energy customers; however, interruption of such secondary sales (as well as use of the balance of the current hydro surplus) to service firm industrial loads will secure much higher revenues for Yukon Energy without incurring material increases in its costs. Under regulated rates, the net benefits of such rate revenue improvements will therefore flow through to reduce overall regulated rates below levels that would otherwise apply. Yukon Energy and YECL customers will accordingly benefit to the extent that rate reduction savings do not simply serve to reduce Rate Stabilization Fund subsidies funded by the Yukon Government.

[7] An example is the BC government directive that BC Hydro not develop nuclear power. In contrast, at times Newfoundland has had a moratorium on developing new small hydro.

objectives have been focused on development, where economically feasible, of local resources compared to imported diesel fuel. Consequently, at times since it was established, Yukon Energy (along with Yukon Development) has assessed, requested proposals, and in some cases conducted research and development projects on the following: Eagle Plains crude oil, wind generation, diesel/coal combined cycle generation (based on coal from Division Mountain), new hydro (including small Independent Power Producer (IPP) hydro projects), diesel/solar hybrid, biomass generation and geothermal resources (many of these at scales well below that needed to supply industrial customers). Planning for major new supply continues to reflect largely the broad "development of local resources" objective where economically feasible.

5.1.3 Planning Framework

The planning framework in this chapter focuses on information that is currently available and on activities Yukon Energy (and the YUB) can control – monitoring potential loads as they develop, conducting appropriate screening and pre-feasibility work on potentially attractive generating and transmission options, and conducting phased and managed feasibility work where appropriate in advance of industrial developments becoming firmly committed to ensure Yukon Energy "protects" the ability to respond when necessary within the timelines required.

To ensure that relevant longer-term service implications are considered, Yukon Energy examines load scenario requirements in this chapter out to the year 2045; however, the analysis addresses only those generation or transmission supply options that may be required to commence development before 2016.

The analysis and project options identified in this chapter build on the Chapter 4, assuming commitment prior to 2009 for resource projects proposed in Chapter 4. In particular, capacity requirements noted in this Chapter reflect adoption of the revised capacity planning criteria (as set out in Section 3.4) as well as prior commitment to and completion of a Mirrlees Life Extension Project (at 14 MW) plus about 4 MW new diesel capacity by 2012 pursuant to the primary contingent recommendations of Chapter 4 to address "Base Case" loads. This chapter also presumes near term development of Marsh Lake Fall/Winter Storage (1.6 MW of added firm capacity) as well as the Aishihik 3rd Turbine project as proposed in Chapter 4[8], without the Aishihik 2nd Transmission Line project (such that the Aishihik 3rd Turbine has no effect on meeting the N-1 capacity planning criteria and only 0.6 MW towards the LOLE criteria), and

[8] In addition to any capacity-related impacts, Marsh Lake Storage and the Aishihik 3rd Turbine as proposed in Chapter 4 together add about 13 GW.h/year to long-term average WAF hydro energy supply (assuming sufficient WAF loads).

takes into consideration the possible near term development of the Carmacks to Stewart Crossing Transmission as reviewed in Chapter 4.

As noted, Chapter 5 identifies four representative industrial development "scenarios" (rather than "forecasts") in order to identify basic planning options for the Resource Plan to consider with regard to different ranges of potential industrial load sizes (as well as load timing, expected life and general location). Individual industrial development opportunities and/or resource supply projects, however, are not the focus of the Chapter 5 analysis.

Four key factors are simultaneously considered in the Chapter 5 screening of potential new resource supply options for each WAF industrial load scenario:

1. **Generation cost of energy supplied by new resource (LCOE):** A primary consideration is the basic generation cost of energy supplied by output from any new resource (with typical focus on overall unit cost per kW.h as opposed to cost per MW of capacity). For the purposes of initial screening, "levelized costs of energy" or LCOE can be used to determine the unit costs/kW.h at the project site of energy produced. Levelized costs reflect the costs of the plant amortized over its life (all kW.h units available to be produced by the plant) assessed on real dollar (2005$) economic terms (i.e., assuming the levelized unit cost after 2005 increases with inflation each year).
    - LCOE focuses only on key generation cost components for a resource option as needed to screen or compare alternative resource options.
    - LCOE for hydro supply projects accordingly focuses in most instances only on capital costs, as these tend to establish the primary overall generation cost for this option. Operating and maintenance costs for large projects can be quite modest (0.5% of capital cost based on BC Hydro estimates) which would tend to increase the LCOE by about 9.4%. Smaller hydro project operating and maintenance costs may vary up to 1.0% to 1.5% of capital cost, which can increase LCOE by 18.8% to 28.3% over the levels estimated in this chapter.
    - In the case of other resource options which involve material fuel operating costs (e.g., diesel generation, or thermal generation using coal, wood biomass or natural gas) it is also necessary that the LCOE reflect fuel as well as capital costs (if the capital costs are also likely to be a key part of the option's overall costs).
    - LCOE automatically takes into consideration variations in the economic lives of alternative resource options.
    - LCOE implicitly assumes that all energy generated over the economic life of a resource option is sold at rates that fully recover the LCOE costs, i.e., this screening tool does not

address the extent to which a resource option may be oversized to meet forecast loads, or otherwise mismatched with forecast loads (in terms of, say, seasonal consideration).

2. **Location of supply and cost of transmission to loads:** If attractive supply options (such as hydro) can be identified that offer lower levelized generation costs of energy (LCOE) than diesel power generation, it is necessary also to screen separately based on location, as low-cost supply options that are materially away from existing transmission systems may not be able to support the costs of major new transmission to connect to the system (particularly for small plants). Similarly, in some cases supply options that are too remote will result in transmission losses that undermine otherwise attractive LCOEs.

3. **Load fit with resource option supply:** Despite a new low cost source of supply being available to Yukon Energy (as assessed based on LCOE per kW.h as well as on location relative to the forecast loads), the overall economics of a resource option also depend ultimately on the supply having actual economic value to the system (such as by displacing energy that otherwise would have needed to be generated using diesel fuel). If some or all of the power provided by a new supply source is surplus to system firm load requirements (e.g., becomes spilled hydro) even very low cost resource options can be uneconomic to the overall power system. Key considerations for section 5.4 on "pre-assessment and screening" therefore focus on "load fit", or how well any given resource project might fit the load requirements (energy in particular) over the next 40 years, how many years of surplus energy may arise if a resource project were to be constructed, and the market risks associated with potential pre-mature closure of industrial customers.

4. **Other associated charges, such as "water rentals" and taxes:** For hydro resource projects that are developed in BC, additional annual charges will be levied on the project that would not be in place if the project was located in Yukon. It is therefore relevant to consider these additional charges when screening such projects in the Resource Plan.

Other major screening factors must separately be considered within the process for evaluating, developing and constructing new power generation facilities, such as environmental factors which may preclude certain developments, or drive material added capital or operating costs (such as for environmental mitigation activities).

The organization and approach adopted in Chapter 5, with its focus on four different industrial load scenarios, reflect the overall importance of "load fit" within the resource option screening process. As reviewed in Sections 5.3 and 5.4, the scale of the industrial loads associated with each scenario drives the identification of relevant resource option technologies. Based on initial screening for this basic "load fit", further screening can then be carried out in accordance with the four key factors noted above.

5.2 REQUIREMENTS

There is a diverse range of industrial development opportunities that could develop in the Yukon during the 20 year planning period, providing an equally diverse range of potential opportunities to develop new energy resources.

At present, base metal prices in particular are at high levels and mining exploration in Yukon has expanded. Yukon Energy has worked with the Government of Yukon Mineral Development Branch to identify potential future mining industrial customers based on specific prospects and proponents, as well as based on the nature of the development, its expected life, and its location in relation to developed grid power.

Larger opportunities may be presented by an Alaska Highway Pipeline, and information on the potential loads for pipeline pumping (which could be served by electricity under certain circumstances) has been included in the planning exercise.

Potential industrial developments considered in this chapter are detailed in *Table 5.1 Industrial Development Opportunities*. Locations of these potential developments are indicated in *Figure 5.1: Map of Industrial Development Opportunities and Power Infrastructure*.

Figure 5.1:
Map of Industrial Development Opportunities and Power Infrastructure

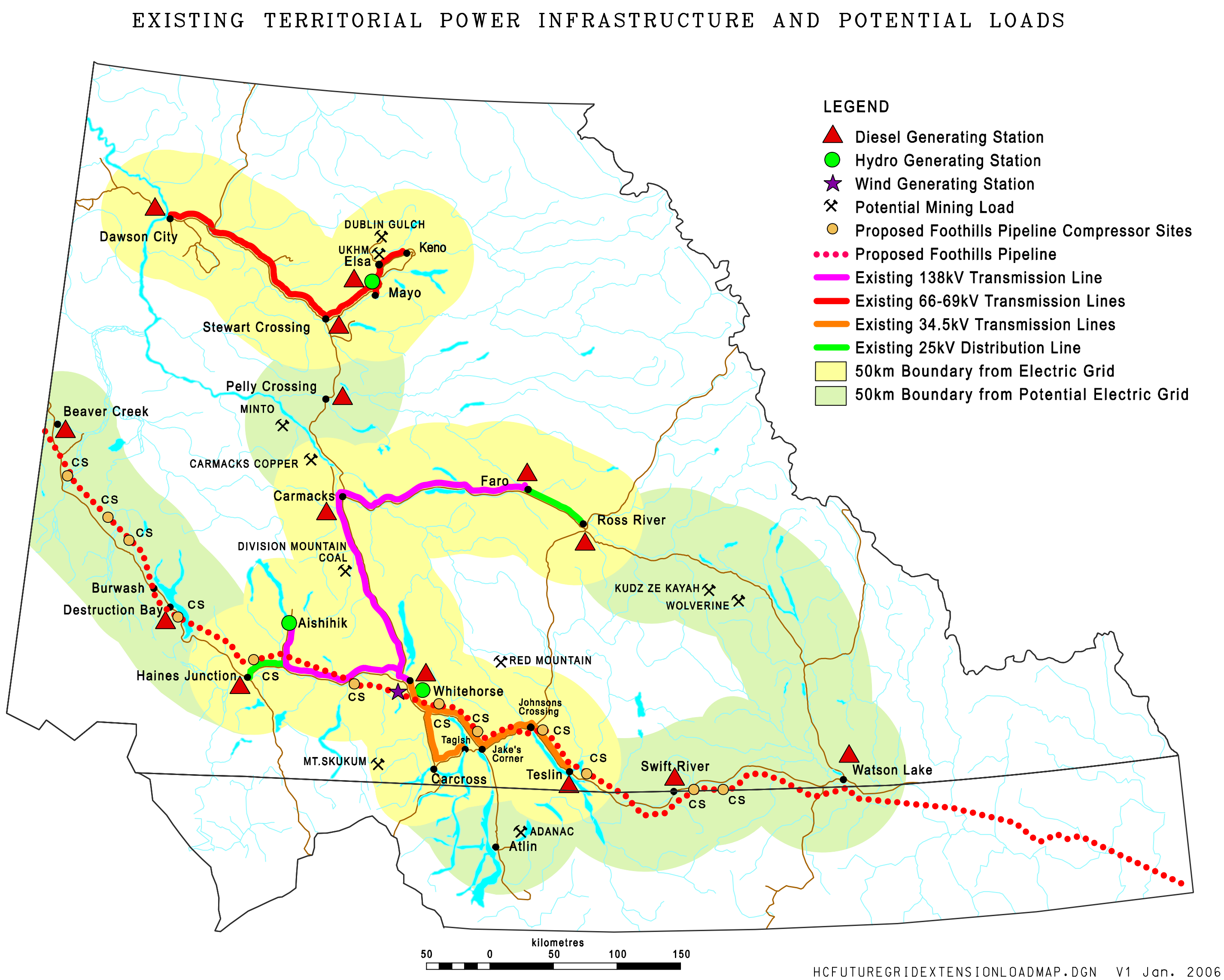


Table 5.1:
Industrial Development Opportunities

Project	Proponent	Location	Grid	Commodity	Road Access	Distance To Grid (km)	Peak Demand (MW)	Annual Energy (GW.h)	Project Life	Assumed In-Service Date
Alaska Highway Pipeline, WAF										
120 MW to 360 MW[1]										
Kluane Compressor	Foothills Pipeline	kmp 214 Destruction Bay	WAF	Natural Gas	Alaska Highway	147.2	30	223.4	30	2012-15
Champagne Compressor	Foothills Pipeline	kmp 378 Stony Creek	WAF	Natural Gas	Alaska Highway	3	30	223.4	30	2012-15
Marsh Lake Compressor	Foothills Pipeline	kmp 455.8 Marsh Lk. Outlet	WAF	Natural Gas	Alaska Highway	30	30	223.4	30	2012-15
Rancheria Compressor	Foothills Pipeline	kmp 739.2	WAF	Natural Gas	Alaska Highway	330	30	223.4	30	2012-15
Potential Mine Developments, WAF										
11 to 20 MW										
Division Mountain Coal	Cash Minerals Ltd.	Braeburn	WAF	Coal	Klondike Highway	20	15	105	15	2010
Red Mountain	Tintina Mines Ltd.	80 km NE of Whitehorse	WAF	Moly	no road access	83	11 to 20	81 to 126	20	2009
Adanac	Adanac	124 KM SE of Whitehorse (in BC)	WAF	Molybdenum	road via Altin	approx. 120	15	Unknown	20	2010
1 to 10 MW										
Minto Property	Sherwood Mining Corp.	100 km NW of Carmacks	WAF	Cu, Ag, Au	Klondike Highway	98	2	14	12	2007
Carmacks Copper	Western Silver Corp.	28 km NW of Carmacks	WAF	Cu, Ag, Au	Freegold Road	53	7	50	8.5	2008
Wolverine	Yukon Zinc	130 km SE Ross River	WAF	Cu, Pb, Zn, Ag, Au	Robert Campbell	273	5.1	37	9	2009
Kudz Ze Kayah	Teck	110 km SE Ross River	WAF	Cu, Pb, Zn, Ag, Au	Robert Campbell	218	8.8	63	11	2011
Mt. Skukum	Tagish Lake Gold Corp	40 km W of Carcross	WAF	Au, Ag	Annie Lake Road	47	1.5 to 2.7	11 to 20	8	2008
Potential Mine Developments, MD										
1 to 10 MW										
Dublin Gulch Property	Strata Gold Corp.	40 km N of Mayo	MD	Au	road north of Elsa	27	4	20	10	2009
UKHM	Under YTG Management (in due diligence)	Elsa	MD	Ag, Zn, Pb	Elsa	0	2	14	5	2007

1-The initial four compressor stations are shown here. Up to eight additional compressor stations (each with similar 30 MW potential load) could be added within the following four to five years. The pipeline electrical loads in this table assume use of electric power rather than natural gas from the pipeline to run these compressor stations. There will also be some ancillary pipeline power loads in any event (not shown here) even if the compressor stations use natural gas.

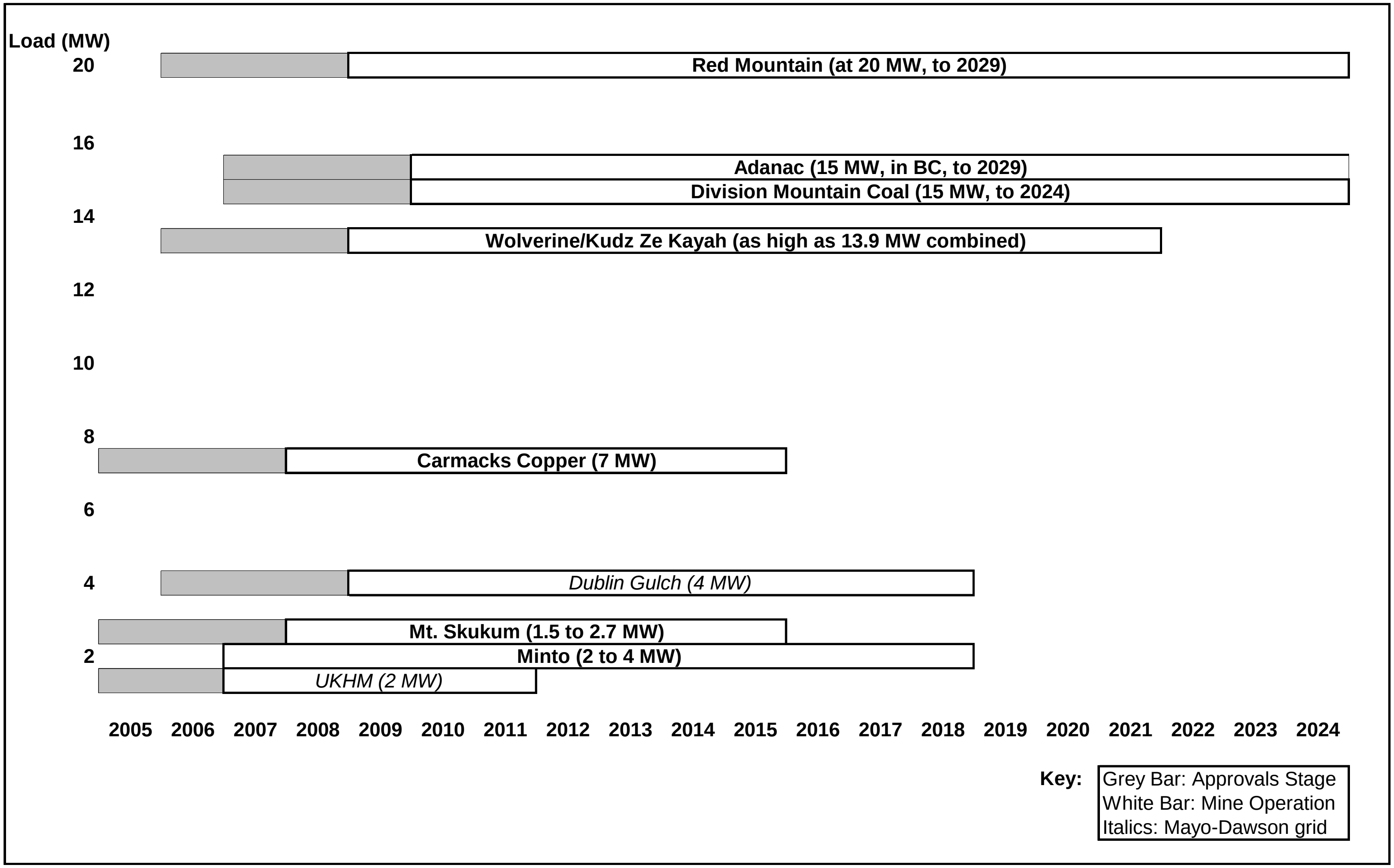
Figure 5.2 Earliest In-Service Dates and Power Loads for Potential Mine Developments illustrates the currently estimated potential timelines associated with mining load opportunities being considered.

Individual industrial developments noted in Table 5.1 and Figure 5.2 could result in possible new generation projects starting construction before 2016, based on industrial load requirements ranging from 2 MW to 360 MW and energy requirements ranging from 11 GW.h to 2,680 GW.h per year, and with service lives ranging from 5 to 30 years or more.

Many of the potential industrial mine loads considered in this chapter are well beyond the bounds of existing transmission, which may limit opportunities for grid service unless other outside funding (such as YTG) is available to enable the connection and eliminate potential adverse rate impacts. The mine developments noted in this chapter are within 273 km of either the WAF or MD grids (see Table 5.1).

When considering the potential "start dates" and development uncertainties for any of the mine projects considered in this chapter it is relevant to note that many of the industrial developments being considered today have been under active consideration as "near term development" prospects for some time. Yukon Energy's internal Resource Plan update process in 1996/97, for example included many of these projects as "advanced mineral projects" relevant at that time for possible power requirements, including Minto, Kutz Ze Kayah, Dublin Gulch, UKHM and Carmacks Copper as projects then engaged in environmental permitting (with all of these developments then expected to use on-site diesel, except for Carmacks Copper and UKHM which were then expected to secure grid power), and including Division Mountain Coal (grid power) and Mt. Skukum (on-site diesel) as projects with anticipated environmental review. Rates approved by the YUB from the 1996/97 GRA included a "New Mine Rider" (Rider K) to address adjustment of retail rates throughout Yukon in the event either Carmacks Copper (WAF) and/or UKHM (Mayo system) was connected to a system in 1996 or 1997.

Figure 5.2:
Earliest In-Service Dates and Power Loads for Potential Mine Developments



To address forecasting uncertainty regarding these industrial development opportunities, four "scenarios" have been selected related to industrial development. Given the range of potential development options, the four scenarios allow Yukon Energy to identify basic planning options relevant to consider in the Resource Plan. If and when specific loads of a certain magnitude develop, Yukon Energy can at that time refine and develop specific plans for serving the load.

Industrial Development Scenarios and Opportunities identified for this Resource Plan focus on the WAF grid (includes possible MD supply options if the Carmacks-Stewart Transmission project is developed) and include:

- **Scenario 1: A 10 MW WAF Industrial Scenario:** This scenario includes one to two smaller mines, which are represented in the analysis by the addition of the Minto (2 MW to 4 MW) and Carmacks Copper (7 MW) mines.
- **Scenario 2: A 25 MW WAF Industrial Scenario:** This scenario includes multiple major developments comparable overall to the traditional load impact of the Faro Mine when it was operating. This scenario is roughly based on the development of three mines, focused on: Minto (2 MW to 4 MW), plus Carmacks Copper (7 MW) and either Red Mountain (11 MW to 20 MW) or Division Mountain coal for export markets (15 MW).
- **Scenario 3: A 40 MW WAF Industrial Scenario:** A larger 40 MW scenario is considered to focus on a potential major mining industry development scenario in Yukon. This scale of mining power load would be in excess of the loads experienced when the Faro mine was operating. As an example, such a scenario could be enabled by the development of Minto (2 MW to 4 MW), plus Carmacks Copper (7 MW) plus Red Mountain at the largest load level assumed to date Mountain (11.3 MW to 20 MW, likely at larger end of scale) plus Division Mountain coal for export markets (15 MW).
- **Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario:** This largest scenario is based on the development of an Alaska Highway Natural Gas Pipeline in the 2012-2015 period and assumes that this development elects to use electricity for pipeline compression. The magnitude of power use is based on an initial four compressor stations at 30 MW each, ultimately being expanded over time to 12 compressor stations at 30 MW each, each with a life of 30 years.

All scenarios forecast non-industrial loads at the Base Case level from Chapter 4 and reflect schedule in-service of projects recommended in Chapter 4 including Aishihik 3rd Turbine, Marsh Lake Fall/Winter Storage and Mirrlees Life Extension. For simplicity, it is also assumed that additional diesel capacity (about 3-4 MW) is developed to meet the balance of the Base Case capacity required by 2012; as noted in Chapter 4, Base Case options in this regard include replacing the smaller third Mirrlees unit (4 MW) with a larger new diesel unit (8-11 MW).

The following Chapter 5 requirements analysis also initially assumes reliance on new diesel generation to supply additional new capacity required to meet new industrial loads.

5.2.1 Scenario 1: A 10 MW WAF Industrial Scenario

Within the next number of years, there is a credible scenario of Yukon Energy potentially connecting service to two mining loads at Minto (Sherwood Mining Corporation) and Carmacks Copper (Western Silver Corporation). Analysis of a 10 MW load scenario, however, is applicable for other potential load developments of a similar scale (including potentially Mt. Skukum gold at 2 MW, Red Mountain in its smallest form at 11 MW, or major expansion of transmission along the Robert Campbell highway to connect Kudz ze Kayah at 8.8 MW or Wolverine at 5.1 MW should other non-utility funding be available to develop transmission along this route).

Focusing on the development of Minto and Carmacks Copper, the projects together would likely have a capacity requirement of 9 MW to 11 MW, and up to 64 GW.h of annual energy sales (about 70 GW.h of annual generation). The projects are not expected to be long-lived. Minto is expected to start in 2007 and run for 12 years. Carmacks Copper is expected to start in 2008 and run for 8.5 years. These starting dates may be delayed by other processes and development timelines.

The Scenario 1 loads are equivalent to the “Base Case with Mine Loads” discussed in detail in section 4.2.6 of Chapter 4, except that the Chapter 5 approach to determining requirements presumes previous near term completion (before 2012) of the Mirrlees Life Extension and installation of 3-4 MW of additional diesel generation, as well as near term development of Marsh Lake Fall/Winter Storage (by 2008) and the Aishihik 3rd Turbine (2009).

Capacity: Based on the revised capacity planning criteria (see Chapter 3), up to 6-7 MW of mining load can be added to the WAF system without driving a need for any new capacity. Even the addition of 10 MW of mining load may not drive any need for new capacity if this new load is either matched with some degree of on-site diesel capability at the mines, or peaks at times other than the current coincident peaks of residential and commercial customers on the coldest days of the year[9]. However, absent any on-site

[9] Assuming only modest on-site diesel in each case (about 20-40% of the peak load), there would be no incremental requirement for capacity on the YEC system in order to serve this scale of mining load.

diesel at the mines, development of this scale will drive an added capacity requirement of up to about 2-3 MW by 2012 compared to the Base Case[10].

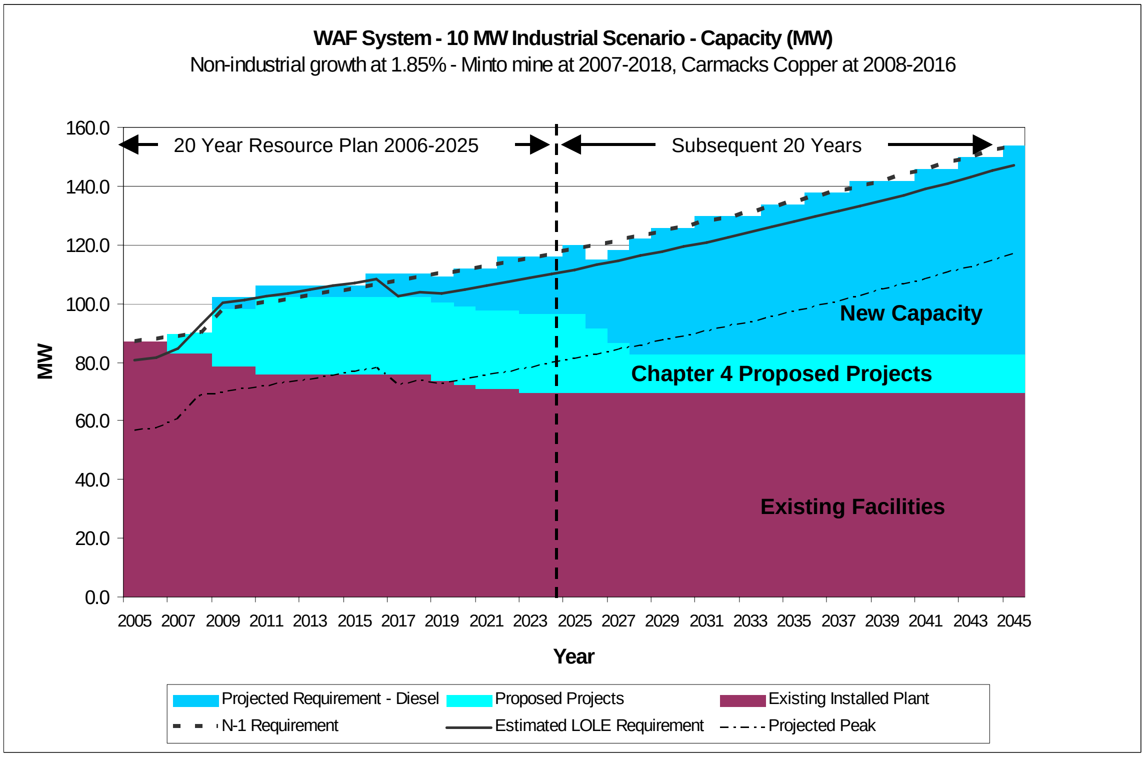
The WAF integrated system peak loads once the two mines are connected would approach the 65-70 MW level, growing to about 78 MW by the end of the mine life[11],

With the current installed plant (and including the proposed 7 MW of hydro from the Aishihik 3rd Turbine and 1.6 MW of new capacity with the Marsh Lake Fall/Winter Storage), YEC can reliably supply about 62 to 63 MW of peak load with hydro (higher in some winters depending on Yukon River flows). Consequently, Yukon Energy would need to rely at times on dispatching up to 15 to 16 MW of diesel capacity during a relatively limited number of hours at the coldest times of the winter to meet peak loads. This is well within the system capability from a reliability/capacity perspective.

[10] Based on the earlier more detailed review in Section 4.2.6, prior to addition of the Aishihik 3rd turbine and Marsh Lake Fall/Winter Storage, the two mines add 2.8 MW to the firm WAF capacity needed (assuming no on-site mine diesel capacity). This is because the mines are assumed at 9 MW (2 MW for Minto plus 7 MW for Carmacks Copper) but 6.2 MW of this load can be carried under the LOLE criteria without driving a need for new capacity (once the mines are connected, the LOLE criteria drives new capacity additions, not N-1). However, later in Chapter 4, the Aishihik 3rd turbine project is proposed to proceed, which adds 0.6 MW to LOLE load carrying capability, so the incremental effect of the mine loads drops to 2.2 MW. Accordingly, the incremental impact on capacity requirements in 2012 due to these two mines would be about 2.2 MW. However, it is noted that a portion of the 2.2 MW requirement may be met by either on-site diesel, or by Chapter 4 projects that add capacity beyond the strict amounts required through 2012. (Chapter 4 assumed, to meet Base Case loads, 18.7 MW is installed separately through implementation of the Chapter 4 proposed actions regarding Marsh Lake Fall/Winter Storage at 1.6 MW, Mirrlees Life Extension at 14 MW plus at least 3.1 MW of new diesel at Whitehorse to address the remaining shortfall. As noted in Chapter 4, a 4 MW new diesel unit may be installed (resulting in a surplus of 0.9 Mw at 2012 under Base Case conditions), the third (4 MW) Mirrlees unit might be replaced by new diesel at from 8 to 11 MW (resulting in surplus capacity under Base Case of between 0.9 and 3.9 MW), or the Carmacks to Stewart Transmission might be developed (providing surplus capacity under Base Case conditions of 1.9 to 2.9 MW of added capacity).)

[11] Chapter 5 assumes that new mine loads are consistent throughout the winter, even at very low temperatures – this may not be correct as some mining operations are limited in terms of the activities they can pursue once temperatures drop to very cold levels.

Figure 5.3:
Scenario 1: WAF Capacity Requirements



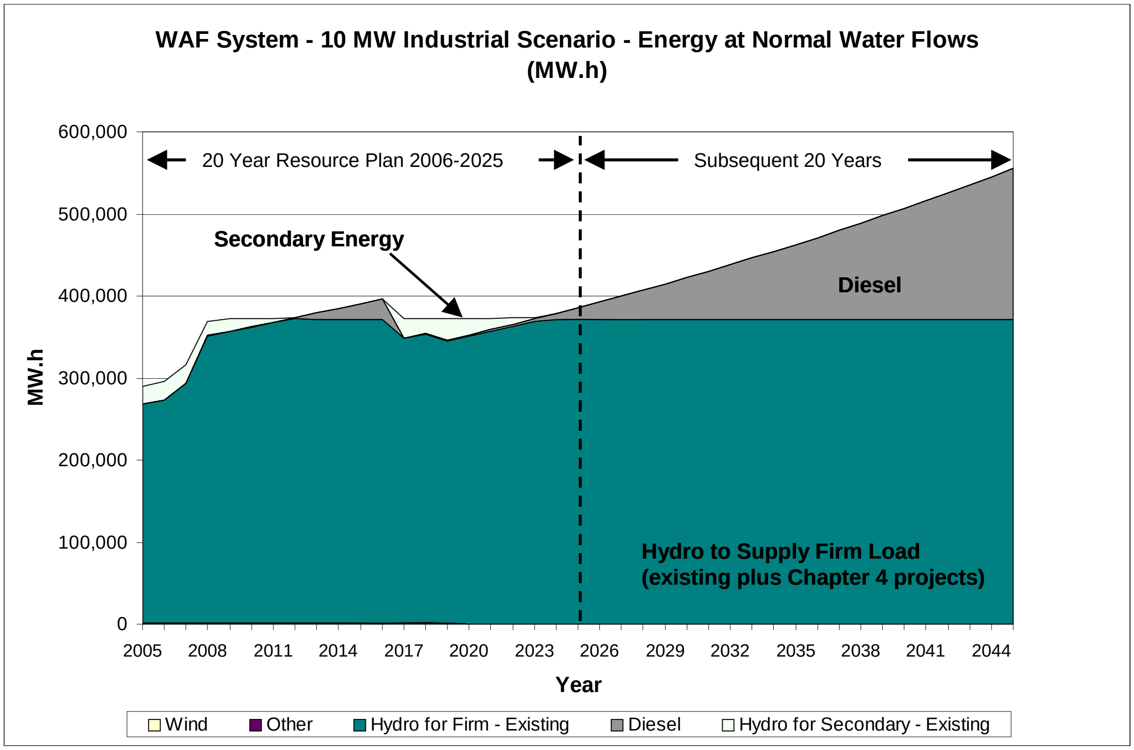
Energy: Under this scenario, surplus WAF hydro would provide most of the incremental energy needs if the mines are connected to WAF. From an energy perspective, the development of Minto and Carmacks Copper are well suited to the current scale of system surplus hydro. At the assumed time of their expected connection (2007-2008), basically the entire loads of these two customers can likely be served with surplus hydro for most of the year (with the relatively minor exception of winter peaking as noted above, subject to receiving further confirmation regarding the seasonality of the loads).

However, diesel generation use would increase throughout the period while the mines are connected. Assuming development of Marsh Lake Storage and the Aishihik 3rd Turbine (as proposed in Chapter 4 to capture energy benefits as noted), diesel generation of 2 GW.h to 25 GW.h per year would arise in the period 2012-2016 (prior to the expected closure of Carmacks Copper in 2017)[12]. After 2017, surplus

[12] Over the life of the two mines as assumed in Scenario 1, about 10% of the incremental energy requirement is supplied by diesel generation in Figure 5.3.

hydro would return to the system for about 7 years to 2023, when base load diesel would again be required, in this case due to non-industrial load growth.[13]

Figure 5.4:
Scenario 1: WAF Energy Requirements



The load balance information above notes a small incremental requirement for diesel generation under this scenario. However, over the next 20 years (the period of the current Resource Plan) the maximum diesel requirements at normal water flows in any year is about 25 GW.h/year, with only 4 of the 20 years above 10 GW.h/year. Diesel requirements for the remaining 16 years vary from about 0.1 GW.h/year to 8 GW.h/year and average about 2 GW.h/year. Under this load scenario, it would be difficult to justify even considering new energy projects for commitment before 2016 based on mine loads of up to 10 MW that are not sustained well beyond 2016[14].

[13] See Appendix C, Table C.5 for a review of diesel requirements by year assuming these two mine loads as well as development of Marsh Lake Fall/Winter Storage and the Aishihik 3rd Turbine.

[14] Variations on Scenario 1 might change this conclusion, i.e., if the same mine development was delayed until about 2016, sustained levels of diesel generation into the future 20 years and beyond would be much higher. However, this type of variation provides minimal guidance to Yukon Energy Resource Plan activities during the next several years.

5.2.2 Scenario 2: A 25 MW WAF Industrial Scenario

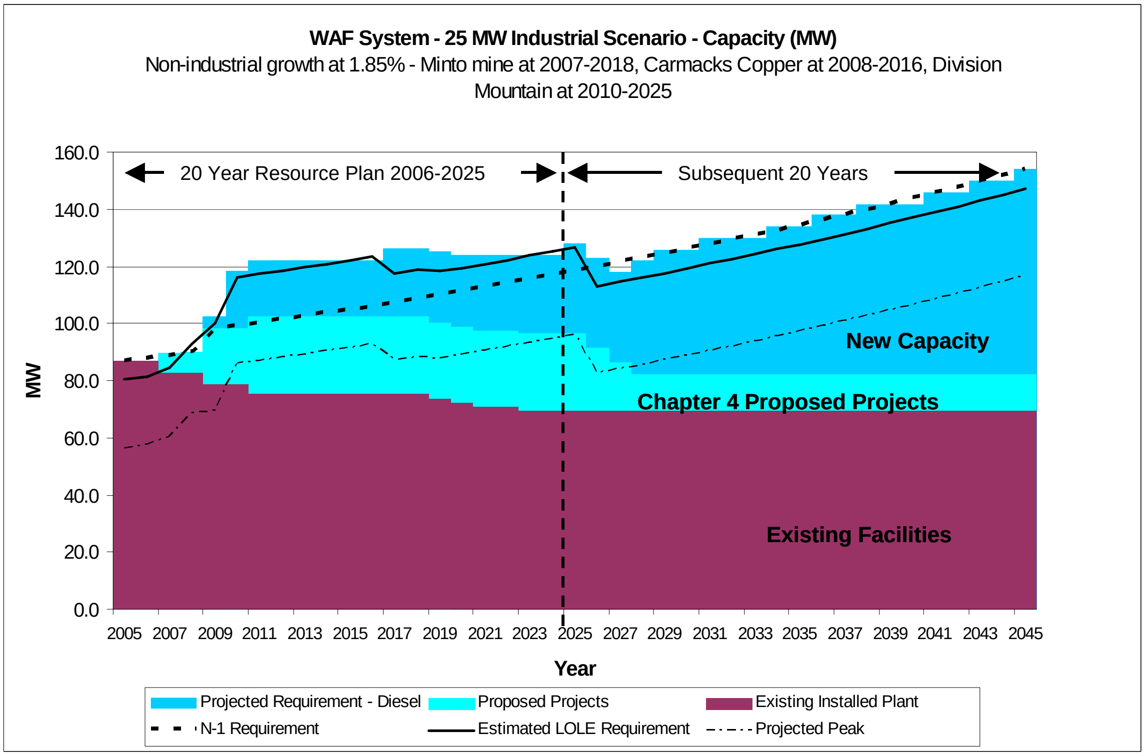
The 25 MW industrial scenario focuses on a larger load development, based on service to Minto and Carmacks Copper via new transmission north from Carmacks, plus additional major industrial load in the 10-20 MW range, with serious potential candidates being Division Mountain coal (15 MW, at Braeburn on existing WAF transmission) or Red Mountain (11.3 MW - 20 MW, north of Johnson's Crossing, requiring 70-100 km or more of new major transmission).

The scenario is examined assuming development of Minto, Carmacks Copper per the loads in Scenario 1, plus Division Mountain coal (15 MW load assumed at 105 GW.h/year from 2010 for 15 years). Overall supply requirements are similar to what existed to supply the Faro mine loads when it was last operating, and approximate 180 GW.h/year of incremental generation when all three mines are operating.

Capacity: If this scenario were to arise, Yukon Energy would face substantial requirements for new capacity in excess of that indicated in Chapter 4. This added capacity required for these industrial loads would potentially be up to an additional 17.2 MW of new diesel units or equivalent capacity, assuming minimal on-site diesel installations at the three mines[15].

[15] As noted in the summary of requirements, the scenario case is modeled using a maximum 24 MW of industrial load. Of this amount, and assuming development of the Aishihik 3rd Turbine, 6.8 MW of industrial load may be carried under the LOLE criteria without a need for new capacity (over Base Load N-1 requirements), and 17.2 MW of new capacity is therefore required.

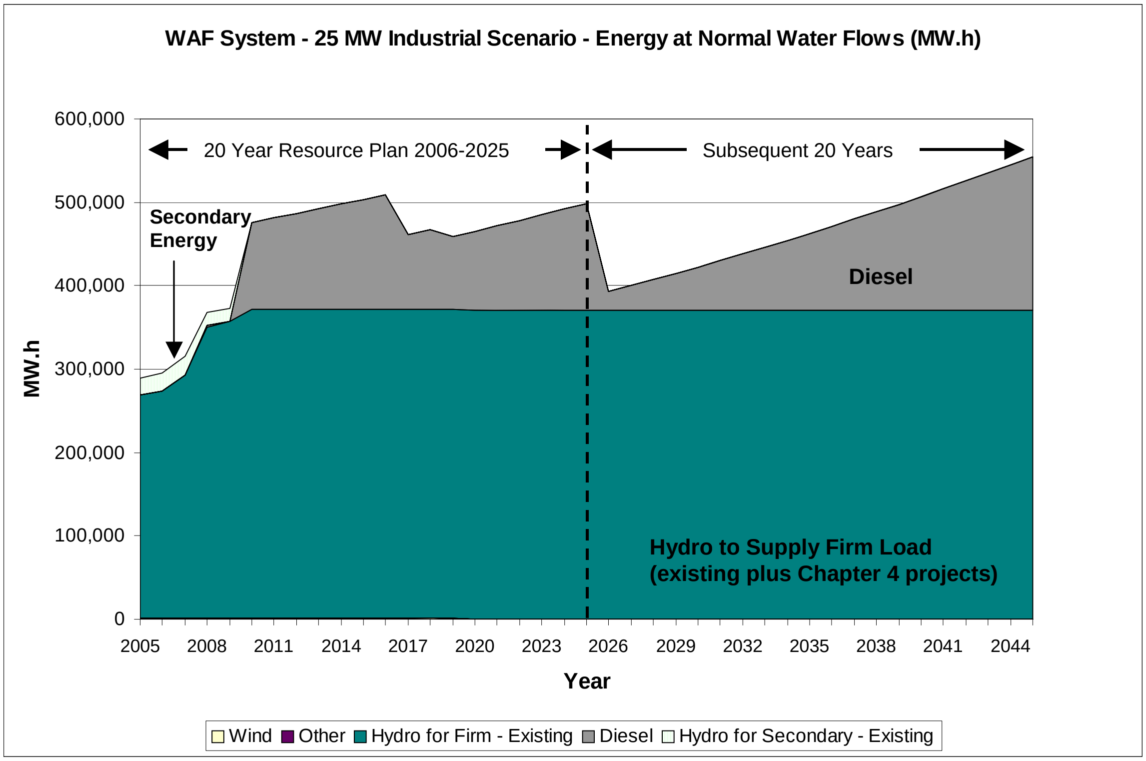
Figure 5.5:
Scenario 2: WAF Capacity Requirements



The WAF integrated system peak loads once the two mines are connected would approach the 85-95 MW level during the mine lives under the assumptions adopted. However, given the scale of the mine loads in this case and without development of new non-diesel generation, the WAF diesel units would be operating for basically the entire year (similar to when Faro was in operation) so “peaking diesel” would no longer be a relevant concept for the YEC WAF system.

Energy: This scenario gives rise to major new requirements for diesel baseload generation, which over the life of the mines would supply about 70% of the mine load incremental generation. Without new development of hydro or other capital intensive generation, WAF diesel fuel generation required would range from about 90 to 140 GW.h/year for a period of 16 years (from 2010 to 2025); thereafter, as the new industrial loads close, diesel generation would approximate 21 GW.h/year (growing each year by 7 to 8 GW.h as WAF non-industrial load grows) and not reaching the 100 GW.h per year level again for 10 years (until 2036), well outside the horizon of the current Resource Plan.

Figure 5.6:
Scenario 2: WAF Energy Requirements



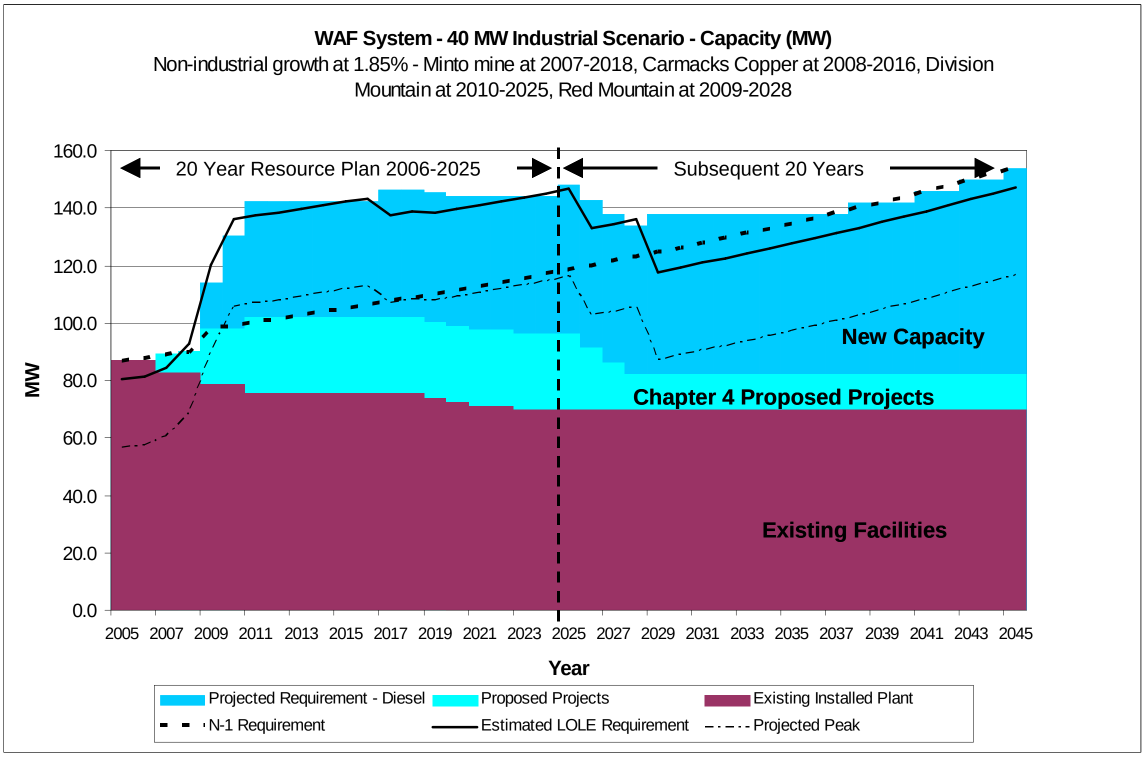
5.2.3 Scenario 3: A 40 MW WAF Industrial Scenario

This scenario is based on an assumption that Yukon Energy is able to connect service to numerous new mining developments and that these developments coincide in the next 10 years. A larger scenario in excess of the Faro mine, this scenario could potentially include the same mines identified in the 25 MW industrial scenario, with the development of the Red Mountain mine. Other possible development combinations in this scenario (but more distant from current grids) including Adanac (15 MW) and Kutz Ze Kayah and Wolverine (8.8 and 5.1 MW) should other non-utility funding enable transmission development along this route.

The specific scenario developed for analysis assumes four new mines all coming into service no later than 2010. These mines include Minto, Carmacks Copper, and Division Mountain per Scenario 2 (the 25 MW scenario), plus Red Mountain assumed to be developed at 20 MW and 126 GW.h/year from 2009 for 20 years (also requiring 70-100 km or more of new major transmission). Without new development of hydro or other capital intensive generation, overall generation supply requirements would approximate 315 GW.h/year when all four of these mines are operating.

Capacity: The scale and duration of development of this major combination of mining loads is such that material increases in system installed capacity are required to service the loads. Yukon Energy would face substantial requirements for new capacity in excess of that indicated in Chapter 4. This added capacity required with these industrial loads would be more than 35 MW of new diesel units or equivalent capacity, assuming minimal on-site diesel installations at the four mines[16].

Figure 5.7:
Scenario 3: WAF Capacity Requirements



Energy: From an energy perspective, the development of 40 MW of industrial load well exceeds the current scale of system surplus hydro. For a period of 16 years, the magnitude of diesel generation under this scenario (if all new energy was supplied by diesel fuel generation) would range from 220 to 275 GW.h at normal water flows, with four additional “shoulder” years before and after the peak averaging 120 to 170 GW.h. Without new development of hydro or other capital intensive generation, over the life of the mines diesel generation would supply about 85% of the mine load incremental generation.

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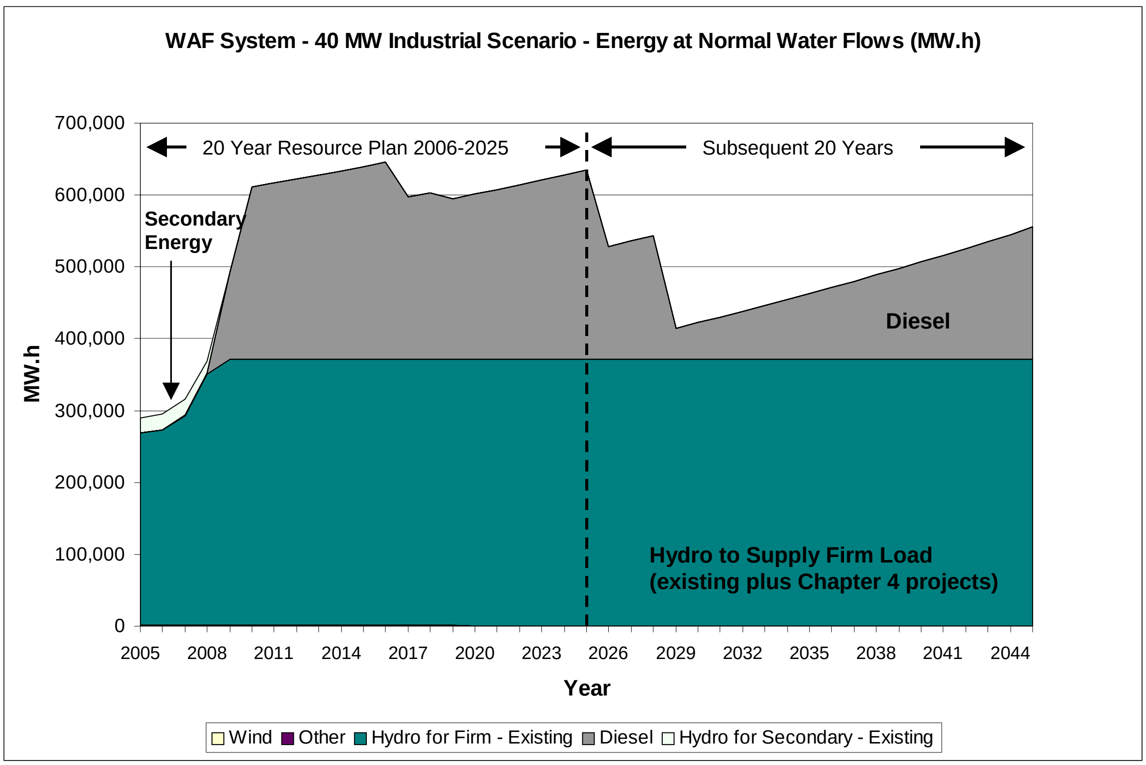
[16] As noted in the summary of requirements, the scenario case is modeled using a maximum 44 MW of industrial load. Of this amount, and assuming development of the Aishihik 3rd Turbine, 6.8 MW of industrial load may be carried under the LOLE criteria without a need for new capacity (over Base Load N-1 requirements), and 37.2 MW of new capacity is therefore required.

After the period of mine closures (assumed here at 2029), the WAF system under this scenario would be back down to a non-industrial load level that requires all the existing hydro output plus about 44 GW.h of diesel generation, and it will take approximately 13 years (assuming no additional new industrial developments) before it increases back to the 150 GW.h of diesel generation level (to 2042). This period is well beyond the current 20 year Resource Plan framework.

Figure 5.8:
Scenario 3: WAF Energy Requirements



5.2.4 Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline

The largest potential industrial power load in the near-term in Yukon is the Alaska Highway Pipeline. For the purposes of current planning, Yukon Energy is working with initial plans that four compressor stations each potentially requiring 30 MW and 223 GW.h/year for 30 years may require service (totalling up to 120 MW and 894 GW.h/year). The earliest in-service date for the first four compressors is assumed to be in the 2012-2015 period, assuming development of the pipeline by this time as well as use of electric power rather than natural gas from the pipeline to run these compressor stations. Up to eight additional

30 MW compressors could be added within the following four to five years (potential total 360 MW and 2,680 GW.h/year for this scenario).

Under normal circumstances, a natural gas pipeline operating in remote areas will power compressor stations with direct drive natural gas compressors without the use of electricity. In areas where there is access to low cost electrical power, pipelines have been converting to electrically powered compressors. In Yukon, the terms of the current agreement relating to this pipeline state that the proponent will be required to use electric compression if it can be provided on a "reasonably economic" basis. Accordingly, the Scenario 4 potential power load is contingent not only on the pipeline being developed as assumed, but also on Yukon Energy being able to establish that it can provide a "reasonably economic" electricity option for the pipeline to use electric compression.

Capacity and energy graphs indicating existing supply versus new 120-360 MW loads for Scenario 4 are not meaningful, given the current installed winter capacity for the entire WAF grid at only 87 MW.

5.3 OPTIONS

New generation options to supply future industrial developments focus on energy rather than capacity requirements.

New industrial WAF power loads beyond Scenario 1 levels would lead to increased reliance on available diesel generation to meet incremental baseload energy requirements[17], and high costs associated with non-peaking diesel energy generation would thereby create opportunities to develop new supply resources to displace the need for incremental diesel energy generation. In each scenario, non-diesel energy resource development opportunities are shaped by the magnitude and duration (seasonal and multi-year) of the incremental baseload energy that would otherwise need to be supplied by available diesel generation.

Yukon Energy has identified on technical grounds an initial list of potential generation options to examine

[17] "Baseload" here means annual energy generation other than "peaking" energy generation. "Peaking" energy generation is generation that occurs in any year only over short-term periods (hours or days) to aid in meeting the peak demand (MW) for electricity, typically during business day hours in winter; peaking generation units accordingly will typically operate only a small percent of the time in any year (e.g., say up to 10% to 15% of total annual hours). In contrast, typical baseload generation units will typically operate for most of the time in any year, e.g., Whitehorse Rapids hydro units (40 MW capacity) on a long-term basis will generate about 246 GW.h/year, implying average annual operation at about 70% of annual capacity. Due to seasonal as well as peaking operation, long-term average annual energy generation at Aishihik approximates only about 40% of the plant's 30 MW capacity.

for each of the four WAF industrial development scenarios (in addition to diesel generation as a standard default option, and transmission required to connect new industrial loads and/or new generation under each scenario).

At this stage, further to discussions related to the 1992 YUB hearing, the Resource Plan also considers briefly potential development of resource options by IPPs.

5.3.1 Overview of Resource Supply Options

Major power resource supply technology options considered in this chapter for possible commitment before 2016 fall into one of three categories: hydro, thermal (coal, or potentially biomass), or natural gas. Potential interconnection to the BC grid is also considered with the pipeline scenario.

For the major supply options considered, the relevant technology characteristics of each type are critical to considering its suitability to the loads to be served during the planning period. Beyond the major supply technology options considered in this chapter, a number of other technology options have been reviewed and determined to not provide the necessary characteristics for major development options in Yukon at this time. Details on the following additional technology options are set out in *Appendix A: Generation Technologies*), along with review of the major technologies addressed below in this chapter:

- Wind
- Coal-bed methane
- Hydrogen
- Nuclear
- Biomass
- Geothermal
- Solar
- DSM

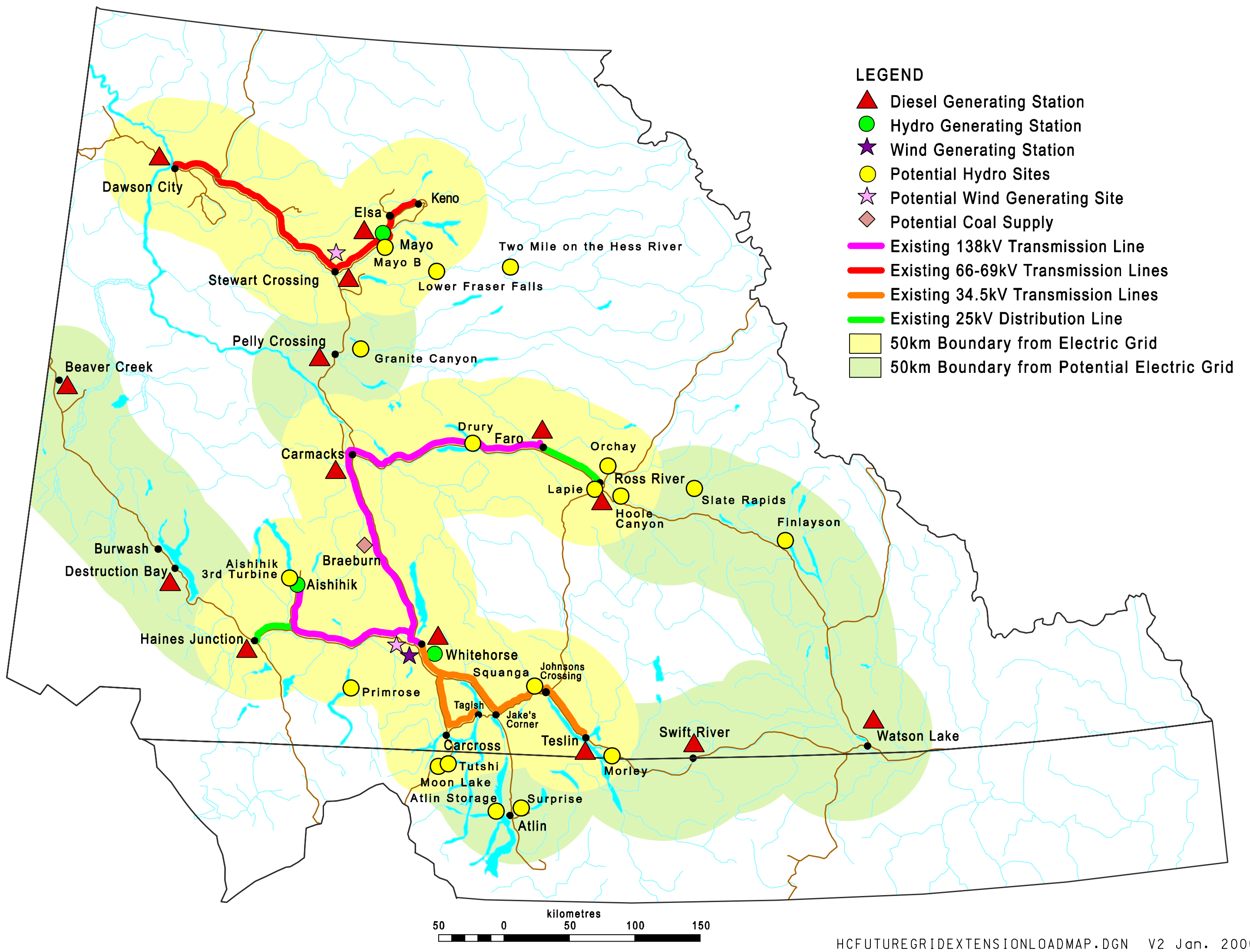
Before reviewing supply options specific to each of the four WAF industrial development scenarios, the technology characteristics for each of the major supply technology options considered in this chapter are highlighted separately below. In addition, potential consideration of IPPs to develop these major resource options is also reviewed.

Figure 5.9: Map of Potential Supply Option Sites provides an overview of hydro and coal site option locations examined in this chapter in the context of the current WAF and MD power supply infrastructure, identifying as well areas within a 50 km boundary from current and potential electric grids.

Figure 5.9:

Map of Potential Supply Option Sites

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL SUPPLY OPTIONS



5.3.1.1 Hydro Technology Characteristics

The potential hydro supply options identified in the Resource Plan for the Yukon are detailed in *Table 5.2: Potential Hydro Resource Options* as well as in *Appendix B: Hydro Project Options*.

Table 5.2:
Potential Hydro Resource Options[1]

	Grid	Installed MW	GWh	Capital Cost (2005$millions) (excl. trans.)	Trans. Distance (km)	Protected under Yukon land claims	In BC	Capital Cost LCOE (cents/KWh) excl. trans (2005$ real)
Existing Hydro Enhancements								
Aishihik Diversions	WAF	0	total of 24	n/a	0	X		n/a
Atlin Storage	WAF	2	9	n/a	0		X	n/a
Very Small Hydro Projects (1-4 MW)								
Drury	WAF	2.6	23	31	0	X		7.2
Squanga	WAF	1.75	8.3	12	5			7.7
Orchay	WAF	4.2	27	47	15			9.2
Morley	WAF	4	22	31	30	X		7.5
Lapie	WAF	2	10	14	8			7.4
Small Hydro Projects (5-10 MW)								
Moon	WAF	8.5	50	51	66		X	5.4
Surprise	WAF	8.5	50	50	100		X	5.3
Tutshi	WAF	7.5	50	79	25		X	8.4
Mayo B	MD	10	48	101	0			11.2
Medium Hydro Projects (10-30 MW)								
Primrose	WAF	28	141	191	100			7.2
Finlayson	WAF	17	129	179	230			7.4
Large Hydro Projects (30-60 MW)								
Hoole	WAF	40	275	412	100			8.0
Slate	WAF	42	252	422	172			8.9
Two Mile Canyon on the Hess	MD	53	280	380	n/a	X		7.2
Very Large Hydro Sites (60+ MW)								
Granite	WAF	80 (up to 250)	660	706	125	X		5.7
Fraser Falls	MD	100 (up to 450)	613	555	n/a			4.8
Yukon River *(such as Rink Rapid, Eagles Nest, Five Fingers)*	WAF	various 75-240	n/a	n/a	n/a			n/a

[1] See Appendix B for more information on specific hydro options and for review of Capital Cost LCOE (2005$).

Hydro resource options exist under each of the four industrial development scenarios, addressing new energy requirements that emerge when loads develop sufficiently to fully utilize the current hydro generation surplus on each grid. Hydro is a proven technology in Yukon and considerable effort has been spent over the years to assess and catalogue potential for hydro throughout the territory. Key characteristic of hydro generation include the following:

- **High initial cost of plant, with very low to zero variable costs:** This key characteristic of hydro derives from the nature of the "fuel" – running water. Consequently, once hydro plants are constructed, they need for economic reasons to be used on a sustained ongoing basis (unless intermittent use is done simply to store water for more cost effective future peaking, seasonal or other use) as there are very little cost savings if the plant is not in use. This leads to situations such as now exist on WAF, where hydro fixed costs are shared across less energy sales than would be the case if the existing hydro assets could be fully utilized by higher firm loads. This is also the economic basis for current WAF and MD secondary sales, essentially to help spread the fixed costs of the hydro plant across more kW.h output units. Consequently, it is difficult to justify hydro projects unless maximum use can be made of the entire output in as many years as possible. The convenient corollary is that hydro project costs are largely incurred up front as capital outlays, so over time the annual expenses accounted for hydro facilities tend to be very stable (with real or constant dollar costs tending to decline[18]) compared with diesel or coal, where nominal fuel costs do tend to increase over time with inflation (among other factors).

- **Very long project lives:** In conjunction with very low variable costs, hydro projects tend to have a very long economic life (in some cases 100 years or more) and accordingly economic justifications for such projects typically also assume sustained and effective use throughout a correspondingly long economic life. As a result the exposure risks related to market requirements or other factors for new hydro projects extend farther into the future than facilities that are expected to provide similar benefits over shorter economic lives.
- **Long lead times for permitting, approvals and construction, with substantial investment in planning studies required in advance of determining full project feasibility and making commitments:** The time required to assess, licence and construct a hydro project is much lengthier than for most other generation technologies. The 1992 Resource Plan reviewed in detail the planning stages for a typical hydro project that might have been considered at that time.

Hydro generation project feasibility in each instance is sensitive to certain key factors:

- **Water availability:** Knowledge of dependable flows; head under natural (run of river) water conditions; potential options for reservoir storage and/or diversions; availability of water throughout the year, particularly during winter peak periods; and opportunities for seasonal or multi-year reservoir storage.

[18] By way of example, consider that the bulk of the initial Whitehorse Rapids hydro plant was built in the 1950s for $7.2 million. Today's costs for this plant include depreciation on the $7.2 million as well as interest on the undepreciated component of this original capital cost.

- **Generation site:** Foundation conditions; general terrain; and access during construction and operation.
- **Project location:** Distance from existing and expected future loads; and transmission requirements.
- **Regulatory approvals:** Environmental and socio-economic impacts; and mitigation requirements.

When undertaking hydro project planning, there is a need for sequential planning stages given the relatively high potential planning costs for each potential site. Experience establishes that project selection should be in clearly defined stages in order to control time and cost commitments, to account for environmental regulatory requirements as well as technical, economic and financial issues, and to allow for an orderly project screening and assessment before commitment and construction of any project without unnecessarily committing excessive capital for assessing multiple sites to the same level of detail.

The 1992 Resource Plan set out three levels or stages for hydro project planning and selection in Yukon, with the need for any site to proceed successfully through all three stages before any commitments may be considered.

- **Level 1/Stage 1 – River Reconnaissance/Inventory (all sites):** Air reconnaissance to locate/evaluate potential sites; existing water flow data. In the 1992 Resource Plan, Level 1 was estimated to cost $20,000 per site (resulting cost estimates considered to be within +/- 50%). Yukon Energy has developed an inventory of many sites in Yukon and in northern BC that have been studied in the past (primarily by NCPC or Government of Canada, and reviewed from time to time by Yukon Energy). Based on inventory of sites studied in the past, Yukon Energy has identified certain sites in this Resource Plan with the potential to meet the forecast electricity needs of Yukon under each of the four industrial development scenarios.
- **Level 2/Stage 2 – Site Reconnaissance/Pre-Feasibility:** Field investigations to evaluate foundation conditions, preliminary hydrological studies, preliminary office studies (power availability, structural lay-outs and capital costs at +/- 25% accuracy), confirm or reject some of the key initial assumptions in an inventory study and provide some data needed for further studies if justified. In the 1992 Resource Plan, Level 2 was estimated to cost $80,000 per site. Level 2 was achieved at a minimum for all sites reviewed in the 1992 Resource Plan report.

- **Level 3/Stage 3 – Feasibility Studies**: Further field investigations (geological reports, foundation investigations through test pitting and drilling, construction material investigations to finalize sources), site topography (scale 1:20,000 or 2 m contours), updated hydrology, environmental and socio-economic studies, consultations with First Nations and others, detailed office studies (to determine structure sizing and location, final concept, power availability, and project capital cost at +/-20% accuracy). In the 1992 Resource Plan, Level 3 was estimated to cost $400,000 per site. Level 3 should be substantially completed prior to any decision to proceed to licensing; required for regulatory submissions, construction contract packages, financing arrangements. Level 3 review was started on only some of the projects examined in the 1992 Resource Plan report (only some of the small scale projects).

The cost today to carry out each Stage/Level of site specific planning would be higher than indicated in the 1992 Resource Plan, both to reflect current day dollars and to reflect any current projects that are larger or more complex than those considered in 1992. Costs to proceed through full scale feasibility studies, licencing/permitting and final design/costing prior to any final commitments for even a "small" hydro project (5-10 MW) might, for example, range from $5 to $10 million[19].

Yukon Energy will only proceed with the final design and construction of sites (effectively Level 4 or Stage 4) that are required (based on load growth, or commitments by industrial customers), that can be successfully licensed in a timely manner, and that are not expected to have a long-term adverse impact on ratepayers relative to other available options.

5.3.1.2 Coal and other Thermal Technology Characteristics

Environmentally sound coal generation is considered in this chapter consistent with past reviews in Yukon based on a presumed pre-development of local supplies (Division Mountain). Coal development solely for power generation, and associated costs of mine development, is not considered.

Coal generation has been reviewed a number of times for application in Yukon. Coal in particular as a fuel source has also been examined in many other jurisdictions beyond Yukon, and is a major generation option that is subject to extensive ongoing technology development to address emissions controls as well as other features (see also Appendix A). Key characteristics of coal relevant to the WAF system are as follows:

- **Economics very sensitive to size of plant:** Repeated assessment of coal potential in Yukon has focused on 20 MW size, as that is the largest single unit that WAF could handle

[19] Estimate based on 10% of estimated capital costs from Table 5.2.

within operating reliability considerations. Economic preference exists for larger plants up to 50 MW or more to secure lower costs per kW.h of output. This size sensitivity extends to capital costs and operating costs (i.e., largely need same material staff complement for 20 MW plant as for 50 MW[20]). However, energy output from larger potential sizes of plant at perhaps 360 GW.h per year (50 MW) are well in excess of most WAF scenario requirements other than the Pipeline.

- **Technologies for use of coal have been advancing at a rapid pace**, particularly with regard to reducing emissions. Any coal generation plant would have to be environmentally sound in order to be considered by Yukon Energy.
- **Facility life of 20-30 years can be well suited to Yukon loads:** The industrial loads in Yukon can allow for large loads of limited life, with risks of major reductions at the end of the life of the mine(s). With a hydro development, the long life of the facility can increase the exposure to this market risk, while the 20-30 year life of coal or other thermal plants is better suited to the timelines of mine life for many developments and to the mitigating of risks of load decreases when the mine closes.

Similar to coal, biomass generation (i.e., wood waste) is subject to the same economic constraints. Specifically, the fixed costs (including fixed operating and maintenance costs) do not vary dramatically with the size of the operation or the load. In these circumstances, economic viability hinges on relatively large and virtually constantly run facilities. As a general principle, however, biomass generation in Yukon would not typically become economic unless three key conditions are met (these same conclusions have also recently been cited as preconditions for biomass electricity generation in Alaska - see Appendix A):

1. The fuel (typically wood) must be available from a source that would otherwise have to pay to dispose of it. Economic biomass generation is not typically possible even outside Yukon with a wood product that has a cost to harvest. Biomass generating facilities at a minimum typically need a secure source of forestry waste biomass such as sawdust or bark waste from a pulp mill that is in close proximity to the biomass generating plant or even (in at least some cases) that can be delivered to the plant for free; for this precondition to apply, there often has to be savings achieved from avoided disposal costs.
2. The wood-fired power displaces diesel power.
3. The waste heat from the biomass generation also must be of economic value on-site, or be able to be sold.

[20] An earlier study for YDC indicated that 13 staff FTE would be required to operate a 20 MW plant. This number was not sensitive to size (in the extreme, a 1 MW plant was considered and determined to still require 12 staff FTE).

To date, proposals discussed in Yukon do not meet any of these three key criteria, and accordingly the thermal biomass option is not considered likely to be economically feasible for commitment prior to 2016 for any of the industrial development scenarios being considered.

5.3.1.3 Natural Gas Technology Characteristics

Natural gas generation is a major supply option to southern utilities (as well as NWT in Inuvik) that may become an option in Yukon if the Alaska Highway Pipeline project proceeds. The current expectation is that any pipeline developed along the Alaska Highway will allow access for at least the major centers to natural gas for local distribution. However, there appears to be uncertainty as to pricing regimes for bulk gas delivered to Yukon.

In terms of the Resource Plan, potential for Natural Gas availability focuses on three major areas:

- **Natural Gas used by the pipeline for compression:** As reviewed earlier in Section 5.2.4, under normal circumstances a natural gas pipeline operating in remote areas will power compressor stations with direct drive natural gas compressors without the use of electricity. In areas where there is access to low cost electrical power, pipelines have been converting to electrically powered compressors. In Yukon, the terms of the current agreement relating to this pipeline state that the proponent will be required to use electric compression if it can be provided on a "reasonably economic" basis. Outside of compressors, pipelines have reasonably material other electrical loads (including potentially cooling loads) that may be ideal candidates for grid power service even if compressor loads are determined to be better served directly by natural gas.
- **Natural Gas for Yukon power generation:** Regardless of whether the pipeline operator uses natural gas or electrically powered compression, the pipeline will likely create opportunities for natural gas based power generation in Yukon. Evidence from southern jurisdictions and NWT indicates that natural gas generation is a major technology option for new power generation and can be well ahead of diesel in terms of costs, reliability and impact on the environment. In addition, unlike coal, natural gas generation is more readily "scalable" to sizes suitably for Yukon as well as more suited to timely regulatory review and approvals and flexibility to operate in response to load variations.
- **Natural gas availability to Yukoners for heating supply:** Natural gas will become a heating supply option for residential and commercial customers under the pipeline scenario. In 1977 Foothills did include a proposal to provide natural gas to communities along the pipeline route including Beaver Creek, Burwash Landing, Destruction Bay, Haines Junction, Whitehorse, Teslin, Upper Liard, and Watson Lake. Although electrical heating is no longer

considered to be a major component of Yukon Energy's loads, there is likely to be some reduction in load (including winter peak loads) from electrical heating customers converting to natural gas.

5.3.1.4 Independent Power Producers

Power delivered to a grid (e.g. through purchases by Yukon Energy) from IPPs rather than generated from assets owned and operated by regulated utilities typically follows the underlying technology characteristics for the generation source used, e.g., IPPs developing hydro sites have some of the same characteristics as utility-developed hydro site projects noted above.

IPPs in certain instances can offer specialized skill, experience, or knowledge that may allow a specific supply option to be cost effectively developed by the IPP to meet utility requirements as stipulated in its contract with the IPP; such contracts are also intended to provide the IPP with unregulated profit incentives to be efficient and effective in supplying such generation outputs. However, there are some unique non-technology characteristics of IPPs that were reviewed in some detail at the 1992 Resource Plan hearings, and that merit specific attention as they may potentially drive material additional risks to a utility and its ratepayers compared to regulated utility power supply projects:

- **Unit pricing, including issues of levelized costs and sharing of benefits from diesel displacement:** As of 1992, the last major YUB review of IPP matters, there remained significant issues outstanding in regards to approaches to pricing for potential IPPs in Yukon. Major issues relate to how to determine the "value" of the IPP to the system (typically based on avoided costs for the system, which can be difficult to calculate for various supply types), how to share between the IPP developer and the utility ratepayers the "benefits" associated with developing lower cost generation, and the potential use of "levelized" nominal prices for IPPs (which tend to provide higher real prices in the near-term and lower real prices over the long-term, and are typically preferred by IPP developers). At a basic level, it is likely that hydro supply projects that can effectively displace regulated utility diesel generation will yield material avoided cost savings within Yukon; however, while almost all such savings will typically go to the benefit of ratepayers when such hydro projects are developed by a regulated utility, the IPP development option introduces a separate step whereby some (or perhaps even all) of the avoided costs savings can be captured by the IPP developer.
- **Take-or-pay contracts:** Similar to other Yukon generators, IPP developers would likely have no market for their power other than the utility. Financing for such IPP projects is expected to require the utility to commit to a "take-or-pay" contract that means the utility will be committed to buy most or all of the project's output at full prices, whether the utility

requires the power or not and perhaps even whether the IPP is able to sustain production of the power. As a result, market and likely other risks of the development can in effect be fully borne by the utility rather than by the IPP developer, even though the IPP may capture most or all of any avoided cost benefits when the facility is able to displace diesel generation. Under some potential IPP arrangements, avoided costs benefits may be locked in for the IPP developer (and paid for by ratepayers as though the diesel savings were in fact occurring) regardless as to whether in fact any such diesel cost savings are being realized by the utility.

- **Delivery of power/reliability:** If an IPP project on a system in Yukon is not functioning at any point in time, regardless as to whether or not the utility must still make payments to the IPP, there is the separate risk that the utility (due to default by the IPP) may not be able to meet its committed supply of power to its ratepayers. However, the utility itself typically has little or no control over the IPP facility, its maintenance activities, emergency procedures, or scheduling and thus can run into problems with the continuity of supply to its customers. For this reason, it is difficult for a regulated utility to treat IPP or other generation not under utility control as "firm" supply for a regulated utility system[21]. A utility also has no control (beyond penalties) over the construction of IPP projects and whether the IPPs can in fact meet key contracted commitments such as in-service date.
- **Financial guarantees:** IPP producers typically seek external bank financing for portions of the capital cost of their facilities. For this reason, these producers typically require power purchase contracts from the regulated utility with strong terms in favour of the IPP and may also include various guarantees from the utility, ultimately focusing the lender's assessment of their risks onto the financial strength of the utility. The end result can be effective requirements for the utility to backstop or guarantee the risks of the private investor to further disproportionately focus the risks of any development on the utility itself and its ratepayers.

Consequently, as discussed in the 1992 hearing, it is difficult to establish an IPP arrangement in Yukon that would reflect a fair sharing of the risks between the utility (and its ratepayers) and the private IPP developer. Yukon Energy in 1996 did complete a major call for "Expressions of Interest" including for IPP supply,. This call yielded some potential focused opportunities for future investigation of small IPPs should material loads develop and base load diesel become an ongoing requirement. However, as noted

[21] As an example, the Snare-Yellowknife system in NWT has a hydro facility that was previously owned and operated by one of the mines. NTPC had a supply agreement with the mine to meet their peak loads in the event the hydro site was not producing. Consequently, when the capacity criteria was assessed for the entire grid, this hydro station was not considered firm capacity for the purposes of planning the system. In 2003 NTPC purchased this station and, now that it no longer is owned and operated as an IPP, it is now included in the new firm capacity planning approach for the system.

in the 1992 hearing, IPP focus in Yukon to date has been on small projects - other than small hydro projects, it remains unclear how difficult it will be in Yukon to develop or negotiate an IPP arrangement to suitably share risks on resource projects of any material size.

5.3.2 Options for Scenario 1: A 10 MW WAF Industrial Scenario

A 10 MW industrial scenario would not likely require the addition of capacity or energy projects. Up to 6-7 MW of industrial load can be added to the system without driving a need for new capacity. Depending on the seasonality of the load and quantity of on-site diesel generation installed by the mines, it is possible that all of the 10 MW in new load could be served without driving a need for new capacity.

There is also a current ability to serve about 90 GW.h per year of energy from existing surplus hydro, decreasing as non-industrial load grows over the life of the mines. Under this scenario, there remains some diesel generation required for peaking and, as the non-industrial load grows, some requirements for baseload diesel. However there is limited value to any new hydro or thermal generation to displace diesel fuel, as the number of hours per year of diesel requirements remains quite limited.[22] In addition, the specific early mine developments considered in Scenario 1 are of relatively short duration (i.e., mine shutdowns are assumed to occur in 2016 and 2017), with the result that surplus hydro is expected to remain under this scenario for half of the 20 year planning period (from 2006 to 2009, and from 2017 to 2022).

As a result, any opportunities for new generation developments are likely limited to existing hydro enhancements (including those identified in Chapter 4, Section 4.3.6) and/or possibly the smallest of the hydro sites identified in Yukon, at most, and likely only those that can provide both capacity and energy benefits. A list of "very small hydro projects" (1-4 MW) is provided in Table 5.2 and in *Appendix B: Hydro Project Options*. Among these options, only Drury is considered to be reasonably well defined at this time.

5.3.3 Options for Scenario 2: A 25 MW WAF Industrial Scenario

A 25 MW industrial scenario, which would be similar to WAF loads experienced when the Faro mine was operating, would provide opportunities for the addition of both capacity and energy. Without new development of hydro or other capital intensive generation, incremental WAF diesel generation required under the Scenario 2 case examined in Section 5.2.2 would range from about 90 to 140 GW.h/year for a

[22] Over the life of these two mines with the timing assumed in Scenario 1, only about 10% of the incremental energy requirement would need to be met by generation beyond that available from current hydro surplus resources (assuming average long-term flows).

period of 16 years (from 2010 to 2025) out of the 180 GW.h/year of overall increased energy required due to the new industrial developments.

Under the Scenario 2 case examined in Section 5.2.2, if no new capital intensive generation was developed and the WAF system had to be served solely with incremental diesel, the assumed industrial loads would only be supplied about 30% with surplus hydro and about 70% with incremental diesel generation over their life. Under these conditions, (i.e., if diesel generation is to be relied upon to supply the incremental energy requirement), there is no apparent basis for Yukon Energy developing any new transmission interconnections to the bulk of this mine load (with the associated risks and transmission losses) rather than the mines simply using isolated diesel plants at their mine site.

However, this scale of industrial load on the WAF system would provide material potential opportunities to develop new capital intensive generation on WAF. If the assumed industrial loads arise, diesel requirements over the life of the industrial loads (absent new capital intensive generation) would approximate 90-140 GW.h/year; however, after the mines close, diesel generation on WAF would fall back to about 21 GW.h/year, growing at about 7 to 8 GW.h/year as non-industrial load grows. Accordingly, the size range of new capital intensive generation suitable for this magnitude of load is likely to be about 50 GW.h per year, or about 7-10 MW of reasonably high capacity factor generation (such as those reviewed in 1992 when the Faro mine was operating)[23]. If such development could be pursued, there would remain 7-10 MW of other new “reserve” capacity required (for largely peaking or standby) where low capital costs are the driving economic factor (i.e., likely new diesel units) over and above the commitments recommended in Chapter 4.

Hydro projects in excess of about 7-10 MW size would impose risks of substantial periods of surplus hydro after the planned closure of the mines (with 10 years required for diesel consumption to move back up to 100 GW.h/year from 2026 to 2036) outside of risks related to premature closure of one or more mines under this scenario.

In contrast, as reviewed below, the scale of diesel generation displacement offered by Scenario 2 appears to be too small to support any feasible thermal coal supply options, even though the overall mine life assumed better fits thermal than hydro supply alternatives.

[23] At that time, projects up to about 8 MW per year and 50 GW.h/year were considered (implied annual capacity factor of 70%).

Hydro: Options can include those identified for the 10 MW scenario (very small hydro projects), as well "small hydro projects" (5-10 MW) and Existing Hydro Enhancements noted in Table 5.2 and *Appendix B: Hydro Project Options*. Aside from Drury, each of these options is considered to be relatively undefined at this time.

The projects identified reflect a lack of suitable hydro sites identified to date in this size range in Yukon. The primary supply options considered in 1992 in this size range (such as Moon Lake as well as Surprise Lake) are in BC and consequently attract significant additional charges for water rental fees and taxes.

Thermal – Coal: There are no credible opportunities to develop coal generation at this scale. As reviewed earlier, the practical minimum size coal development considered for Yukon has been 20 MW, which roughly equates to 144 GW.h/year or well in excess of the requirements under this scenario (other proposals have focused on coal generation in excess of this range up to 50 MW).

5.3.4 Options for Scenario 3: A 40 MW WAF Industrial Scenario

Under the 40 MW scenario, as under the 25 MW scenario, any loads connected to the WAF clearly push the system well onto diesel. Without new development of hydro or other capital intensive generation, incremental WAF diesel generation required under the Scenario 3 case examined in Section 5.2.3 would range from 220 to 275 GW.h/year for a period of 16 years, with four additional "shoulder" years averaging about 120 to 170 GW.h/year. After these mines close (assumed to be 2029), diesel generation on WAF for non-industrial loads would fall back to about 44 GW.h/year, growing at about 7 to 8 GW.h/year as non-industrial load grows.

If diesel was relied upon to supply loads of this magnitude, the industrial loads in effect would only be supplied about 15% with existing surplus hydro and 85% with incremental diesel generation over their life. As noted above for the Scenario 2 case, if WAF diesel generation is to be relied upon there is no apparent basis for Yukon Energy developing any new transmission interconnections to the bulk of this mine load (with the associated risks and transmission losses) rather than the mines simply using isolated diesel plants at their mine site. Consequently, if such loads are to be considered for connection to WAF, a major focus is required on developing new capital intensive generation larger than the 50 GW.h/year (7-10 MW) examined under Scenario 2 options.

New capital intensive energy projects in the range of 50 GW.h/year (about 7-10 MW) would be expected to be fully utilized in each year of this scenario. In contrast, long-term capital intensive energy projects in the range of 150 GW.h/year (in the range of 20-30 MW if baseload) would experience about 13 years or more of surplus energy after the closure of the mines until non-industrial load growth consumed the excess output. Projects in excess of this level would see about 20 years of sustained use, then significant periods where they far exceed system requirements.

Overall, hydro project options above about 100 GW.h per year may be difficult to justify unless there is substantial expectation of subsequent industrial loads after 2024, and solid measures to address downside risks of premature mine closings. Thermal coal project options, however, with levels of energy generation of about 150 GW.h/year that are focused on a 20-year life may become feasible at this scale of mine loads. Each of these options is reviewed below, and is considered to be relatively undefined at this time.

Hydro: Hydro projects to supply the 40 MW scenario result in significant issues with respect to load stability and economic value of power over their life after the planned closure of the mines (outside of risks related to premature closure). This is because hydro projects are very long-term investments that can produce power well beyond the expected life of the mine being considered.

At this size range, options can include those identified for the 5-10 MW scenario (small hydro projects), as well "medium hydro projects" (10-30 MW) noted in Table 5.2 and *Appendix B: Hydro Project Options*.

At this size range, projects can support some costs for new transmission, so generation sites within about 50-100 km or more of the established 138 kV grid become worthy of investigation.

Thermal – Coal: Under the 40 MW scenario, the scale of new requirements increase to a point where opportunities may arise to develop coal or other thermal generation. The practical minimum size coal development considered earlier (1992) for Yukon has been 20 MW which roughly equates to 144 GW.h/year or in the range of the new energy requirements under this scenario. As coal plants have a life more consistent with the mine lives being considered (often assessed for project planning and feasibility at 25 years, although many plants outlive this), the technical fit of a coal plant to the loads under this scenario is better than hydro in this size range.

The economics of coal generation are very sensitive to the price of the coal, as well as to the quality of the coal and emissions standards, which can materially impact the capital costs required for the plant (for example, ash handling and dealing with sulphur in the coal). A 1995 assessment of coal power generation prepared for YDC by H. A. Simons Ltd. using Division Mountain coal determined a $50 million capital cost (1995$) excluding mine development costs, as well as about $2 million (1995$) for non-fuel annual operating and maintenance costs (including 13 staff positions). Further assessment in 1996 focused on the potential for coal at $30/tonne to allow for power generation (using a 20 MW plant) at 8 cents/kW.h (1996$).

Based on these earlier 1995/96 estimates, a coal plant could be constructed and operated on the following basis:

- 25 year life at 20 MW, 144 GW.h (a 20 year life is also assessed below).
- $61 million capital cost (2005$), $2.5 million per year non-fuel operating cost (2005$) excluding taxes.
- Coal requirements of 102,000 T per year at $37/T (1995 estimate of $30/T inflated to 2005$).
- Oil requirement of 2.3 million litres at $0.65/litre (2005$) – based on 1995 estimate of 2,220 T/year[24].

The result is an 8.3 cents/kW.h LCOE (2005$, real), excluding transmission and taxes (but in this case including operating and maintenance costs, unlike hydro LCOE costs quoted above, given substantial O&M costs for coal generation) [25].

5.3.5 Options for Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario

Compared to the existing Yukon WAF system (firm non-industrial load of about 270 GW.h per year, installed winter capacity of about 90 MW), the pipeline loads for the first four stations at 120 MW and 894 GW.h/year, are massively in excess of system capability or conditions experienced to date.

Little work has been done since the 1950s and 1960s on hydro sites of the size relevant to this scenario. Any such hydro generation development would involve concurrent major transmission development needs which have not been assessed or costed to date in any detail, although some preliminary transmission concepts have been reviewed.

Timing needed for planning and licensing major generation and transmission projects is likely in excess of ten years, given the need at the outset for extensive and costly pre-feasibility and feasibility studies. This suggests that the pipeline would be operating for many years before the new hydro generation would be

[24] Based on the 1996 study, oil is required to supply the facility during start-up and back up duty. Given increases in the cost of oil since this study was completed, a newer coal plant may have a revised optimal balance between oil and coal, but this has not been assessed.

[25] Coal generation developed to supply a 20 year project life would result in the LCOE being increased to 8.7 cents/kW.h compared to 8.3 cents/kW.h for a 25 year project life (2005$, real)

available. The need for the pipeline operator to install gas compressors at the outset will further reduce the cost effectiveness of the new hydro options. However, previous reviews in Yukon (including the Lysyk inquiry) noted the key importance of the pipeline operator installing stations that can be readily converted to electrical service at a later date if power cannot be coordinated for delivery from the outset of pipeline operation.

The range of potential options for Scenario 4 is reviewed below.

Hydro: Hydro projects to supply the Pipeline scenario are of a magnitude not well understood or recently studied in Yukon. At this size range, options can include more modest "large hydro projects" (30-60 MW) noted in Table 5.2 and *Appendix B: Hydro Project Options* for supply to one or more individual stations, or "very large hydro projects" (60+ MW) for major integrated supply to multiple compressor stations.

At this size range, major redevelopment of Yukon transmission would be required, so transmission is an unresolved issue for all potential generation sites.

Thermal – coal: Power generation from coal can reasonably provide the magnitude of power required to service the pipeline. However, no serious work has been completed in Yukon regarding potential coal developments of this scale. In addition, at least initially coal is not likely to be considered economically viable as supply to electrical compression for the pipeline, as electrical compression is typically attractive to pipeline operators only in low cost hydro-based jurisdictions where rates can be below 6 cents/kW.h to as low as almost 3 cents/kW.h or lower depending on interruptibility (but not typically resorting to electrical compression in higher priced non-hydro jurisdictions dominated by coal).

Interconnection with the BC Grid: There are limited attractive projects in Yukon that have the capability to serve the full power needs of the pipeline. It is possible that such potential new loads would form the basis for BC to extend transmission from BC that would connect Yukon (near Watson Lake) with generation assets located in BC. This option could radically change power supply costs and options in Yukon to the extent that major load centres (e.g., WAF and MD as well as Watson Lake) were linked to this new grid connection.

5.4 PRE-ASSESSMENT AND SCREENING

The options identified under the various scenarios above reflect potential opportunities to put in place capital intensive but overall lower cost sources of supply than alternatives of grid-based diesel supply or isolated diesel supply to the mines.

In assessing grid-based diesel supply, current diesel price forecasts indicate about $0.70/litre to $0.75/litre for Whitehorse for 2010 (based on $50 to $55 US per barrel, 2010$ for NYMEX light sweet crude, reflecting current oil futures markets), equating to about $0.21/kW.h to $0.22/kW.h (2010$, or $0.20/kW.h in 2005$)[26] including modest variable operating and maintenance costs (such as lube), assumed at 0.016/kW.h in 2005$. These costs provide a benchmark for assessing the potential cost competitiveness of any other resource option. These costs also provide an indication of potential ratepayer impacts relating to connection of major new industrial loads if in the end these loads must be supplied through incremental diesel generation.

Based on the information now known to YEC, all potentially feasible generation options noted in the previous sections including their associated transmission, can potentially be economically developed as an alternative to diesel, so long as system loads allow full to near-full use of their output over the life of the project.

There are two major areas of uncertainty, however, that limit ability to develop full detailed assessment of options and conclusions regarding economic and technical feasibility at this time for any specific industrial development scenario:

- There is not sufficient definition of the loads and timing of industrial customers (outside of perhaps Minto at 2-4 MW).
- All project supply options identified above to address these scenarios are at best moderately defined, and most remain relatively undefined. In terms of the hydro project staging, few projects are at Level 2 (Site Reconnaissance/Pre-Feasibility) while most are at Level 1 (River Reconnaissance/Inventory) and in many cases (especially for medium to large projects) even the Level 1 work was completed many decades ago under different expected generation concepts and constraints so is of limited value. Thermal projects are at a similarly early stage in conceptual planning.

The focus of the following pre-assessment and screening is initially on technical pre-assessment and load fit (i.e. how well does the project fit the load requirements under any specific load scenario). As noted, cost effective opportunities to displace diesel generation require full to near-full effective energy use of a resource option's output over its life.

[26] For modeling purposes, fuel costs have been assumed at 65 cents/litre for 2005, inflating at 2% per year, to total 71.77 cents/litre in 2010.

Subsequently, economic pre-assessment is also considered to look at the screening options with respect to economic factors. Within the economic pre-assessment, diesel generation is assumed to be the default source for all energy not supplied by hydro or other resource options under the 10 MW, 25 MW and 40 MW scenarios, as diesel generation provides supply with relatively limited risk related to timing and/or capital costs. Diesel generation is not a reasonable supply option under the pipeline scenario, where the alternative to electrical compression is natural gas driven compression.

5.4.1 Technical Pre-Assessment and Load Fit

The assessment of how well various supply options fit the load requirements focuses around options of various types and size ranges. The analysis focuses on scale of loads relative to scale of various resource project options; however, as noted in Section 5.3, the assumed timing of loads as well as their duration can also be of critical importance in assessing resource options[27].

The load fit assessment is provided separately below for each different supply option technology and scale grouping:

Hydro – Enhancements (Aishihik diversions at no capacity, 1.8-17.7 GW.h/year; Atlin Storage at 2.0 MW, 9.0 GW.h/year; also other potential options being assessed in Southern Lakes; potential planning costs for these projects are estimated to be about $100,000 to $200,000 per project): These projects involve maximizing the value from the existing investments. Under the industrial development scenarios, each focuses on the potential to provide energy as well as in some cases capacity. The projects are all likely to be of relatively modest size that could be relevant under basically all potential industrial scenarios. The planning costs for these projects are estimated to be between $300,000 and $600,000.

Hydro – Very Small (1-4 MW, 5-30 GW.h/year, $12-$47 million; potential planning costs of $1.2 to $4.7 million prior to decision to proceed with project): The projects in this size range

[27] By way of example, a ten year delay in the Scenario 1 mine loads would enhance opportunities to develop at least very small hydro projects (to the extent that non-industrial loads would then have grown sufficiently to sustain long term use of the new energy supply). Similarly, the duration assumed for each mine development load examined is of critical importance in the assessment of resource supply options, e.g., capital intensive supply options can much more easily accommodate loads of 40 years duration than loads of only 10 years duration. In this regard, Scenario 2 and 3 load opportunities relate as much to assumed mine duration (at 15 to 20 years) as to the assumed level or scale of these loads; Scenario 4 load opportunities, with 30 year durations, also elate to more than only scale.

(Drury at 2.6 MW or larger, Squanga at 1.75 MW, also Morley (4 MW), Lapie (2 MW) and Orchay (4.2 MW)) are likely beyond the limits of what can be enabled by the 10 MW industrial development assumed in Scenario 1. The technical assessment of these projects relies on serving a role to supply energy in excess of existing system hydro capability, in order to displace diesel related to serving incremental mine loads while they are in operation, and to displace diesel serving non-industrial loads once the mines close at about 2016-2018. However, absent mine development at or above 10 MW extending through to at least 2020, it is not apparent that the load fit is sufficiently consistent to enable projects of even this very small size range to be feasible. Should they be developed, these projects are well within the financial capability of Yukon Energy/YDC to pursue, including measures to protect against downside market or load related risks.

Hydro – Small (5 -10 MW, 30-70 GW.h/year, $50-$101 million; potential planning costs of $5.0 to $10.1 million prior to decision to proceed with project): Projects in this size range (Moon at 8.5 MW, Tutshi at 7.5 MW, Mayo B at 10 MW) can be enabled by industrial developments in the 25 MW range with relatively limited downside risk outside of premature mine closures over a life of at least 15 to 20 years[28]. These projects are in a size range that can be financed under traditional structures by YEC and YDC, and that YDC likely has the financial capability to “backstop” with respect to various market-related risks. Ongoing current efforts in the southern lakes area may yet identify further potential in this size range for other projects or comparable sized enhancements to the Whitehorse Rapids facility by way of water management projects.

Hydro – Medium (10-30 MW, 70-150 GW.h/year, $179-$191 million; potential planning costs of $17.9 to $19.1 million prior to decision to proceed with project): Sites in this size range (including Primrose at 19-30 MW and Finlayson at 17 MW) only fit the WAF load profile under the largest 40 MW mining scenarios discussed (Scenario 3), which focused on the opening of four mines simultaneously (Minto, Carmacks Copper, Division Mountain and Red Mountain) with lives of 15 to 20 years for most of the load. However, even under these conditions the hydro projects are likely much too large for the system after the closure of the mines (assuming mine closure prior to about 2035), and as such would rely on either new mining loads at that time to sustain the level of WAF energy 20-25 years from now, or would have substantial surplus for likely far many years. In this regard, projects in this size range may also have a difficult time competing with coal with respect to load fit compared to the life of the generating station[29].

[28] Appendix B, Figure B-2 provides a review example of load fit for Moon Lake hydro and the 25 MW Industrial Scenario 2.
[29] Appendix B, Figure B-3 and Figure B-4 provide a review example of load fit for Primrose hydro and the 25 MW Industrial Scenario 2 and 40 MW Industrial Scenario 3.

Serious issues also arise with respect to “market”-related risks in this case such as premature mine closings and even delays in initial development. In addition, these projects are likely at the limits of what YEC/YDC can finance within the existing financial structure. At these limits of the financial capability of YDC and YTG, it would become necessary to identify and/or develop suitable mechanisms within Yukon to “backstop” the downside market risks associated with projects of this size.

Hydro – Large (30-60 MW, about 150-300 GW.h/year, $380-$422 million; potential planning costs of $38.0 to $42.2 million prior to decision to proceed with project): These projects exceed the size required for any credible mining load or combination of loads examined in this Resource Plan and would require well in excess of 40 MW of new mining loads – no such loads or load combinations have been identified to date. Project options in this range focused on Hoole at 40 MW, Slate at 41.6 MW, and Two Mile Canyon on the Hess at 53 MW. There may be options to develop these sites for portions of a pipeline load (1-2 compressors of the planned 4-12 compressor pipeline development), but in all likelihood the economics of a pipeline case will more readily facilitate projects in the 60+ MW range and not multiple projects in the 30-60 MW range. In addition, these projects appear to be at or beyond the absolute limits that Yukon Energy and Yukon Development could potentially finance under any conditions without potential external support or guarantees, such as from Canada.

Hydro – Very Large (60 MW+, over 500 GW.h/year, $555 million+; potential planning costs in excess of $50 million prior to decision to proceed with project): These projects cannot be considered for any practical development without a committed pipeline load (or equivalent) using electricity for compression, and without major transmission system development or redevelopment to handle this scale of generation. The projects identified to date include Granite at 80-250 MW, Fraser Falls at 100-450 MW, and various Yukon River sites at 100-500 MW. Yukon Energy would also need to address financial capability to even plan and carry out pre-construction activities on these projects, as costs for even these pre-development stages would likely exceed Yukon Energy’s ready financial capability. Costs for development would require either major financial partners or government debt guarantees from Canada as commitments are likely beyond the capability of Yukon to guarantee.

Thermal – Coal: Development of environmentally sound coal in a size range of 20 MW or more cannot be seriously considered on the WAF system, given current technology, outside of major industrial developments in the range of 40 MW or higher (i.e., well in excess of the Faro Mine when it was operating). In the event very large industrial mine developments do arise in the 40 MW range, however, coal may be a better fit to the life of the load than hydro, and would therefore merit further consideration at that time.

Coal may provide opportunities within the 25 MW scale of industrial load development (similar to Faro-sized load) if constraints on technical feasibility and cost for coal generation projects smaller than 20 MW can be in some way be addressed. Earlier proposals that considered a technology for 15 MW combined coal/oil system have since been abandoned. However, it will remain relevant to monitor technology developments in this area. The capital costs of a coal facility are in a size range that can be financed under traditional structures by YEC and YDC, and YDC likely has the financial capability to "backstop" with respect to various market-related risks.

Coal options must be environmentally sound to be considered. The feasibility of coal generation will depend to some extent on the cost of employing state of the art technologies to reduce emissions.

Coal options also need to address directly who would be responsible for providing this resource, and under what terms and conditions would Yukon Energy secure such supplies. In the event that a coal mining project is developed for export markets, the coal for local thermal markets may become readily available. It is not clear how such supplies could be economically secured, however before such time as a coal mining project is developed for export markets. Other relevant aspects also require further considerations, including ash disposal.

Thermal – Biomass: In the event that Yukon develops a source for waste wood, of sufficient scale and duration, that would otherwise have a cost associated with disposal (e.g., someone willing to pay Yukon Energy or an IPP to dispose of it) there may develop an option for biomass generation. Currently, no such source of biomass supply is apparent in the time period for this Resource Plan. However, given similar fixed cost constraints as for coal, even if such a source was secured it is not likely that this type of generation would fit the load profiles under any but the largest industrial development scenario (e.g., a 20 MW plant enabled by 40 MW of industrial load).

Natural Gas: The pipeline scenario (Scenario 4) will likely create opportunities for natural gas based power generation in Yukon.

Evidence from southern jurisdictions and NWT indicates that natural gas generation is a major technology option for new power generation and can be well ahead of diesel in terms of costs, reliability and impact on the environment.

In addition, unlike coal, natural gas generation is more readily "scalable" to sizes suitable for Yukon as well as more suited to timely regulatory review and approvals and flexibility to operate in response to load variations. Natural gas generation is also likely to be located near to the main load centres, and thus not subject to the same transmission costs and risks as noted for many other supply options.

It is premature at this time, however, to assess likely charges that will apply for natural gas supplies when they become available[30].

5.4.2 Economic Pre-Assessment

Given a solid load fit in technical pre-assessment, Yukon Energy has an ability to consider in a preliminary way the likely economics of projects to assist in any screening effort. Four key factors come into consideration in this pre-assessment:

1. **Preliminary Generation Capital and fuel-related Levelized Cost/kW.h (LCOE):** At a simple preliminary level, the LCOE noted above can provide a useful screening tool for the various options under consideration.

   Compared to assumed prices for solely the variable cost of diesel at 20 cents/kW.h in 2005$, all supply projects reviewed above have substantial opportunities to produce power over the long-term at a cost lower than diesel.

2. **Transmission Required to access main WAF Grid:** For hydro projects in particular, investment in transmission to connect remote sites with the established transmission system, and associated losses, can be a material factor in project economics. Transmission costs that begin to exceed about 10%-15% of the project costs can be difficult to overcome.

   Rough assumptions to date are that projects in the 1-4 MW range cannot support any material transmission costs beyond simple connection (i.e., must be basically on the established transmission, preferably 138 kV) while 5-10 MW projects may be able to support transmission of 50 km (to perhaps as high as 100 km at a maximum). Projects in the 10-30 MW range may be able to allow for transmission somewhat over 100 km.

   For the large to very large projects (30-60 MW and 60+ MW) there has not been any serious effort to screen based on incremental transmission costs, as this can only likely be usefully considered once loads have been identified and required upgrades or additional circuits to

[30] The Mackenzie Valley Pipeline proponents currently have a proposal before the National Energy Board that includes plans to provide access to gas from the pipeline for use by communities in the NWT along the pipeline route. This proposal, and the current NEB review, may provide guidance as to possible future charges applicable in Yukon after pipeline development in this area.

existing transmission can be incorporated into the assessment – such planning is not possible in the absence of further information about potential loads.

3. **Extra Fees, Charges or Process costs related to hydro developments in BC:** For hydro projects in BC, there is a material additional cost and risk associated with both licencing due to interprovincial processes, as well as water rentals and taxes.

   In Yukon, Yukon Energy does not pay and has complete future protection against any water rentals that may be levied by the federal government for use of waters for power generation. However, such fees are commonplace in other jurisdictions and can result in material costs for the utility (in Manitoba, water rental rates are 0.3 cents/kW.h for generation; rates in BC have been as much as 0.5 cents/kW.h but have recently been under review – the BC charges also include additional amounts for storage of water, as well as taxes). The economics of projects located in BC will require close monitoring of these rates to ensure that these costs are fully included in planning assessments of BC project economics.

4. **Impacts on rates:** Separate economic assessment is required of the effect of any projects on rates, as rates for any given year are set based on annual costs (including depreciation, interest and return on equity) rather than the lifetime long-term costs of projects. Past Yukon experience with the Faro mine well indicates that even long-term economic investments (such as Whitehorse turbine #4) can result in substantial rate impacts in some years when loads drop below the point where the assets are providing economic value[31]. Based on examples in Appendix B, major new hydro projects that have otherwise attractive lifetime LCOE costs can give rise to the potential for serious rate impact risks in some years if loads decline.

   A separate issue with respect to capital intensive projects such as hydro is that annual costs which drive rates are at a maximum in the first few years of the project (when rate base balances are highest). However, the benefits of capital intensive projects tend to increase over time as the value of any diesel displaced increases with inflation or other upward fuel

[31] Past experience with the Faro mine and Whitehorse #4 indicate rate impacts of 20-40% are possible when the Faro mine experienced shut downs in 1993 and 1997/98. This level of rate impact, however, likely understates the true full potential rate impact from major mine closures (i.e., closures for mines that account for a dominant share of WAF loads as was the case with the Faro mine when operating), as in the case of Whitehorse #4 the Government of Canada (via the Canada Flexible Term Note) retained most of the risks with respect to such loads. Absent this mechanism, the rate impact of the 1998 Faro closure would have been about $1 million higher than ultimately experienced (almost 3% higher than the 18.74% increase that ratepayers experienced).

price drivers (this is similar to the Mayo-Dawson Transmission project which will achieve material savings for ratepayers over its life, but did result in the need to address what would otherwise have been adverse rate impacts in the first two years via flexible debt financing[32]). Projects reviewed in the 1992 Resource Plan indicated potential for one to three year adverse impact on rates before savings compared to diesel begin to arise for ratepayers (using a diesel price of $0.26/litre), while Mayo-Dawson Transmission project initial reviews had at times determined the potential for five to ten year adverse impact on rates absent YDC flexible financing (ultimately the flexible financing was only required for 2003 and 2004).

However, due to the higher price of diesel fuel today, rate impacts from each of the resource supply option projects identified above are expected to be positive in year 1 assuming the full output is available to offset diesel generation. For example, Drury at a capital cost of $31 million (2005$) has the potential to offset 23 GW.h of diesel ($4.6 million per year, based diesel on $0.20/kW.h in 2005$). The year 1 costs of Drury (2005$) will total approximately $2.3 million for interest and return on equity (7.52% cost of capital times $31 million[33]) plus about $0.6 million for depreciation (using an aggregate life of hydro-related assets for depreciation of 50 years, and no reserve for salvage). In short, the capital costs of Drury would drive a $1.7 million lower overall system costs in year 1 than supplying this same 23 GW.h with diesel (this ignores what would likely be a relatively small operating and maintenance cost for Drury, but also ignores capital cost benefits from the 2.6 MW of capacity Drury brings to the system avoiding some investment at times in diesel engines).

For Level 2 projects (at this time only includes Drury), full economic assessment can be undertaken once certainty is developed with respect to sustained industrial loads beyond Minto (i.e., Minto is not sufficient to justify any scale of new capital intensive generation).

5.5 PROPOSED ACTIONS

Yukon Energy proposes planning activities as set out below to address a wide range of potential industrial development scenarios beyond the near term, and to protect future opportunities to commit development of additional generation and transmission projects before 2016 in a timely and cost-effective way in the

[32] At this point in time, overall average retail rate increase impacts are likely to be about 1% if utility regulated costs are increased in any one year by $360,000. Rate impacts need to be assessed in this regard by comparing a specific resource option to the available alternative resource options. It is relevant to note that this assessment may prove a resource option to save money relative to diesel, thereby allowing lower rates than would be required with diesel generation, while in reality (due to the need to develop new generation in any event to serve major new loads) overall rates are still being increased.

[33] Note also that Drury has very limited transmission costs required for the facility.

event that one or more of these industrial development scenarios materialize. Planning activities are organized by industrial development load scenario, identifying proposals as to how to approach each load scenario should it arise. "Pre-commitment" activities are also addressed which encompass planning activities Yukon Energy proposes to carry out prior to any certainty or commitment on the part of potential new industrial loads.

5.5.1 Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario

This industrial development scenario (which provides for near term development and operation between 2007 and 2018 of the Minto and Carmacks Copper mines) supports commitment of modest existing hydro enhancements, but does not support commitment of any new hydro site development before 2016 unless mine loads of at least 10 MW are sustained well beyond 2016. Consideration of the smallest hydro site options (1-4 MW) could potentially be supported in the event that 10 MW mine load development extends through to at least 2020. In this context, the following planning activities are recommended in the event these mine loads are seriously being considered for development prior to 2016:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should then proceed to commit the Aishihik 3rd Turbine, the Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments.
  - If not already committed, Aishihik Diversions and Atlin Storage should then be advanced to Level 2 studies, including system-wide water and load dispatch modeling, to quantify the energy benefits under this scenario.
  - Ongoing assessment of the Southern Lakes should be completed to identify additional water control or small hydro opportunities to enhance Whitehorse Rapids output.
- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission line is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility, including enhanced peaking capability.
- **New WAF hydro site development:** If industrial and overall load development commitment is such that both new capacity and baseload diesel generation energy are required through to at least 2020 (and there is no clear indication of more major industrial development scenarios emerging during the 20 year planning period), planning activities should be carried out to enable commitment of a very small hydro site development (1-4 MW, 5-30 GW.h/year)[34] able to provide new capacity and displace diesel energy.

[34] Present estimates of the costs are $12-$47 million generation capital cost (2005$) with potential generation planning costs of $1.2-$4.7 million prior to a decision to proceed with construction.

- Based on current information, this would indicate that the hydro site at Drury should at that time be advanced to full Level 3 studies that include consideration of variations that maximize capacity.
- Possible consideration might also be given to Level 2 studies for Squanga as a utility project or IPP, and/or for Morley, as potential alternatives for comparison to Drury.
- Consideration must include means to mitigate downside risks should industrial loads close prematurely.
- Actual development in each or these cases will involve investments greater than $3 million, or long-term contract commitments in excess of $3 million present value to IPPs, and therefore YUB review will be sought prior to project commitment.

- **Other activities regarding DSM:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused primarily on reduction of system peak demand.

5.5.2 Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 for development of more than 10 MW (70 GW.h/year) but less than about 20-25 MW (comparable to the Faro mine) for a period through to at least 2025, planning activities should be carried out to enable commitment to develop new hydro site resources to provide approximately 50 GW.h per year to WAF.

For potential hydro projects, key options to be considered at such time as greater load certainty develops regarding this level and duration of industrial load are as follows:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should proceed to commit the Aishihik 3rd Turbine, the Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments (see proposals for Scenario 1).
- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility (including any feasible enhanced peaking capability).
- **New hydro site development:** If industrial and overall load development commitment on WAF before 2016 is such that WAF baseload diesel generation energy of more than 10 MW (70 GW.h/year) is then required through to at least 2025 (and there is no clear indication of more major industrial development scenarios establishing new WAF industrial loads in excess

of about 20 MW (about 125 GW.h/year) emerging during the 20 year planning period and extending beyond 2025, planning activities should then be carried out to enable commitment of a small hydro site development (7-10 MW, about 50 GW.h/year[35]) able to provide diesel displacing energy to WAF.

- New hydro options focused on Yukon-based projects, if available, would be the preference.
- However, given limited attractive projects in this size range identified in Yukon to date, further Level 1 and 2 activity should be undertaken if timing permits in areas within 50 km of existing 138 kV WAF transmission focused initially on scans of the various inventory studies completed by NCPC or others.
- Sites in BC, including Moon Lake and Tutshi[36], should have Level 2 studies updated in preparation for this possible load scenario, particularly focusing on the costs and risks associated with interprovincial licencing requirements and water rentals. Level 3 studies should then proceed if warranted.

- **Coal supply possibilities:** In the event that the loads of this scale develop and coal also becomes available from developed Yukon sources, coal generation technology should be reviewed in the event that timing permits to determine the potential for an economic and environmentally sound coal development at sizes below 20 MW, sized as appropriate to fit the industrial loads being developed at that time.
- **Other activities regarding DSM and wind:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused on both the reduction of system peak demand and energy conservation, and development of new wind generation (if attractive sites near established utility grids can be identified).

Actual development of new hydro sites (or any other new generation site) in each case will involve investments greater than $3 million, so YUB review will be sought prior to project commitment. In addition, for larger scale developments, planning and feasibility work may exceed the $3 million level, so there is the potential for YUB review at this earlier stage as well.

5.5.3 Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 of more than about 20-25 MW (150 or more GW.h/year) for a period through to at least 2030, resulting in forecast baseload WAF diesel generation

[35] Present estimates of the costs are $50-$100 million generation capital cost (2005$) with potential generation planning costs of $5-$10 million prior to a decision to proceed with construction.

[36] No further work should proceed on Surprise Lake so long as the community continues its plans to develop micro-hydro at the site.

energy of more than about 150 GW.h/year to be required until at least 2030, then planning activities can reasonably proceed to consider commitments before 2016 to develop new hydro site or coal generation resources of 20-30 MW to provide 130-150 GW.h per year of long-term energy (20 or more years) to WAF.

- **Load uncertainties and low probabilities today:** The industrial loads required to reach the above levels at this time involve significant uncertainties and low probabilities.
- **New medium scale hydro site development (20-30 MW, 130-150 GW.h/year):** The development of generation and transmission to serve these loads, based on currently identified potential hydro sites (Primrose and Finlayson), would involve substantial generation capital costs ($179-$191 million (2005$), excluding transmission, as well as very large planning costs (about $20 million) prior to a decision to proceed with construction. Such costs are likely at or beyond the limits of YEC's current financial capabilities and involve material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line.
- **Coal supply thermal generation possibilities:** Coal resource options of this scale could involve far less capital than comparable new hydro sites, provided that coal supply as such was otherwise available from developed Yukon sources. The scale at 20 MW (140/GW/h/year[37]), however, is still very small for coal thermal technology and would require careful Level 2 and 3 screening and feasibility assessments to confirm its potential feasibility.

For potential generation projects related to the above scales, it is not apparent today that there is sufficient likelihood of this major development scenario arising to justify major investment at this time in planning and feasibility studies for medium new hydro or small coal plants. Accordingly, no specific planning activities are recommended at this time. Future decisions with respect to the level of effort and expense in this area will reflect YEC's ongoing assessment of the probabilities of the required loads developing. For projects of this scale, even early planning and feasibility work (at least on hydro sites) will exceed the $3 million level, in which case YUB review will be sought before proceeding with specific planning commitments of $3 million or more.

5.5.4 Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario

The Scenario 4 pipeline loads at this time involves significant uncertainties as regards timing and magnitudes. However, given the implications of this industrial development for all aspects of Yukon power utility activities, and its clear possibility to come into service within the 20-year period for the

[37] The present estimate of the costs are $ 61 million thermal plant capital cost (2005$), excluding transmission or coal resource development costs, with potential generation planning costs of $6 million or more prior to a decision to proceed with construction.

current Resource Plan, one key activity recommended for the near-term regarding Scenario 4 involves continued active monitoring of this development as well as active planning to identify and assess all potential related material impacts, options and opportunities, including:

- Major power supply options for the pipeline for compression (focusing initially on short listing and assessing at Level 1 knowledge large scale hydro site options and related transmission requirements).
- More modest power supply opportunities focused on compressor station "station service" loads.
- Options to use natural gas for power generation to serve cost effectively other incremental industrial loads.

The development of generation and transmission to serve these pipeline loads is likely well beyond the limits of YEC's current financial capabilities as well as involving material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line. Accordingly, prior to carrying out any planning activities beyond Level 1 assessment of any specific site or technology specific studies, it is proposed that Yukon Energy identify and assess options that would address this constraint, e.g., joint venturing with others, and/or options to secure external government or other financing.

5.5.5 Proposed "Pre-commitment" activities

Prior to any certainty developing regarding the industrial scenarios that may arise, it is proposed that Yukon Energy remain focused on certain key planning activities to ensure protection of the options to address new load requirements. Yukon Energy proposes the following activities in this regard:

- **Monitoring of Industrial load developments:** Yukon Energy will continue to monitor closely potential load development and related spin-off residential and commercial impacts, including necessary discussions with mineral exploration companies active in Yukon, key officials in Yukon government working with mines and other industrial developments, and relevant industry associations. Separately, YEC will maintain ongoing monitoring of potential Alaska Highway pipeline developments and factors that may impact electrical loads in Yukon (including potential for electrical compression).
- **Southern Lakes hydrology assessments:** Continued assessment and studies of the hydrology of the southern lakes area, including identification of potential for water control structures to enhance output of Whitehorse Rapids, as well as potential hydro generation sites.

- **Other existing hydro facility enhancements:** Continued focus on projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases, Mayo. This includes full Level 3 and 4 studies on the Aishihik 3rd turbine and updating Level 2 studies on Aishihik diversions. Where suitable, activities should be carried out in conjunction with other normal Supply Side Enhancement planning by Yukon Energy, such as re-runnering.
- **Level 1 and 2 assessments to identify preferred 5-30 MW scale Yukon hydro sites**: There is an option to invest in further surveying the potential of other Yukon based hydro generation sites to try to identify good sites in the 5-10 MW range (within about 50 km of existing high voltage transmission) and to advance credible candidates in the 5-30 MW range through Level 2 assessments (including ongoing monitoring of hydrology) in order to identify more clearly preferred sites to develop for possible loads within this range. However, this activity is costly and may require assessment of a number of sites. No activities in this regard are recommended today; however, in the event that at least one large industrial load (such as Red Mountain or Division Mountain) proceeds to advanced licencing and likely commitment stages, it is proposed that this initial work should proceed quickly to determine if the sites identified to date are indeed the best candidates or if there are other Yukon-based sites that should be seriously considered, and to identify specific projects for Level 3 feasibility assessments.
- **Ongoing monitoring of hydrology**: Active hydrology monitoring will proceed where feasible for all hydro sites likely to be serious candidates for future development within the 20 year planning period. The monitoring may be periodic (seasonal flow information, current cost of $1,000 per year per site) up to a full-time recording station (at a current cost of $30,000 (initial costs) plus ongoing costs of between $10,000 to $15,000 per year).

APPENDIX A:
POWER RESOURCE TECHNOLOGY OPTIONS

APPENDIX B:
HYDRO PROJECT OPTIONS

APPENDIX C:
AISHIHIK 3RD TURBINE ASSESSMENT

APPENDIX A:
POWER RESOURCE TECHNOLOGY OPTIONS

A.1 POWER RESOURCE TECHNOLOGY OPTIONS

This Appendix provides a brief overview of technology options for providing power resources, either through new generation (supply side) or through Demand Side Management.

A substantial review of power resource options and technologies was provided in the 1992 Yukon Resource Plan. More recent power resource technology overviews have been prepared for northern conditions, most notably the Alaska Power Association overview titled *New Energy for Alaska* published in March 2004 (available online at http://www.areca.org/areca/energy_sys.htm) and a more site-specific review[1] "*Galena Electric power – A Situational Analysis (*pre-publication draft)" (available online at http://www.iser.uaa.alaska.edu/Publications/ Galena_power_draftfinal_15Dec2004.pdf) .

For each technology option reviewed, the scope of consideration from the 1992 Resource Plan is noted, as well as more recent information from either the Alaska studies, or other Yukon specific information compared to 1992.

A.1.1 DIESEL

The 1992 Resource Plan was directed, as per OIC 1992/92 to consider "contracts and commitments for non-diesel fuel generation". At the time, diesel generation was being used for a substantial part of the WAF supply. As such, diesel was not reviewed as a supply option, but was reviewed as the "base case" for comparison of non-diesel alternatives.

Diesel generating units have relatively low capital costs (approximately $1 million per MW), and high operating costs. Consequently, diesel units are typically well-suited to meeting reserve capacity requirements and short-term capacity needs during system peaks. Diesel is also well suited to isolated regions where loads are small (such as the Yukon isolated communities), where loads do not have very long lives (such as temporary applications or short lived mines) or where the heat from the operation of the diesels is of economic value (such as in certain industrial operations). Since diesel units can be turned off when they are not needed (and because of the relatively low capital costs), diesel units provide a relatively lower risk source of supply if loads are uncertain (as load decreases can be met with cost increases from putting the unit on standby).

[1] The draft was published in December of 2004, and provides an overview of generation options for an Alaskan community of 800 people. The options considered for Galena included: diesel, coal, nuclear, and a grid connection.

Diesel is expensive for utility operations running to provide sustained energy on a regular basis throughout the year.

Since 1992, efficiencies of new diesel units have occurred. The 1992 resource plan was based on efficiency of 3.7 kW.h/year and the most efficient units now in service on WAF are cited at 3.9 kW.h/litre (installed in early 1990s). However, the more recent Alaska studies cite potential efficiencies in the 4.18 kW.h/litre range for the most efficient new units (15.8 kW.h/gallon) at maximum efficiency. This maximum may be unattainable over any sustained operating period with normal start-up, shut-down, load variations, and other factors, but does reflect improvements since the 1992 review.

A.1.2 HYDRO

Hydro options were studied extensively as part of the 1992 Resource Plan Submission. In addition to the information provided in the main Resource Plan document in 1992, a separate binder (Supply Side: Binder A), contained detailed information on hydro options evaluated by the utilities.

Hydro generating plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units. Hydro options have the potential to meet the needs of the Yukon under industrial development scenarios.

Hydro options for the Yukon are identified in detail in *Chapter 5: Industrial Developments and Opportunities*, and significant specific characteristics and issues related to hydro are discussed in particular in *Section 5.3: Options*., and *Appendix B: Hydro Project Options*.

A.1.3 WIND

At the time of the 1992 Resource Plan, the Yukon utilities had no wind generation in operation, but wind power was identified as a potential future supply option. Since that time, Yukon Energy, with the support of Yukon Development and the Government of Yukon, has gained considerable experience with wind generation for utility supply. This includes operation of two turbines on Haeckel Hill on WAF (a Bonus 150 of 150 kW installed in 1993 and a Vestas V47 of 660 kW installed in 2000) as well as numerous wind monitoring projects throughout Yukon[2]. At this time, Yukon is consistently cited as a leader in assessing the commercial potential and technical considerations of wind generation in northern climates.

Key issues with respect to wind generation are capital costs (particularly for smaller units), capacity limitations and wind availability. Capital costs for wind generation have been declining in recent years, but remain quite high for installation in Yukon, where major new support systems can be required (transmission and roads are typically required to install wind generation in new sites, which are typically high elevations sites in Yukon). Wind is also not a form of reliable capacity to utility systems, as it is not dispatchable and is an intermittent resource, consequently wind does not make a contribution towards planning for meeting the peak commitments of a utility. Wind is well suited, however, to larger hydro-based systems that have material storage (such as WAF) once material expensive diesel generation begins to be dispatched.

More important to wind economics, the feasibility of wind is very sensitive to wind regime and availability. Utility industry experience indicates that wind economics essentially require a capacity factor of 30%[3] while high grade commercial installations may be higher. By comparison, wind turbines installed in Yukon have only been able to achieve an average capacity factor of 22% given the wind regime and other operational factors (such as rime icing, which can substantially reduce wind output) and a Community Wind Resource Assessment program run by YDC has surveyed a number of sites in Yukon (focused on potential customer wind installations) with capacity factors of 2% to a little over 10%. Two utility focused projects were investigated at Destruction Bay and Old Crow. Each was found to have an uneconomic wind regime compared to project costs.

Wind generators can be installed reasonably quickly (outside of the time to order new units, which today have significant lead times due to market demand). Capital costs risks related to wind primarily relate to associated infrastructure (such as roads and transmission lines needed to access the proposed site).

Capital costs for new wind generators continue to reduce in price fairly substantially. However, the scale of new wind turbine models is also growing, and is now approaching a range that would not be able to be easily integrated into Yukon systems other than WAF (1.5 MW or more per unit). On WAF, future industrial loads that push the system onto material diesel generation may enable commercial

[2] Sites at Mt. Sumanik, Destruction Bay, Haines Junction, Tagish, Whitehorse, Dawson City, and Ferry Hill have been undertaken since the early 1980s. Three locations suitable for wind generation were identified in the WAF area: Haeckel Hill, Mount Sumanik and Flat Mountain. Monitoring of potential commercial wind sites continues, including under the Yukon Development Community Wind Resource Assessment Program.

[3] p. 8, Yukon Energy Resources: Wind. March 1997.

development of wind as a complement to other resources reviewed in this plan. Given the rapid evolution of the wind industry and technology, updated assessment of the potential for wind will need to made once potential industrial loads become further defined.

In the north, the Northwest Territories Power Corporation has excluded wind generation from their resource planning for the current time, as a result of the challenges of operating wind turbines. In Alaska a number of remote communities have developed wind generation to supplement isolated diesel, but there are not utility wind turbines on the major interconnected systems. Also, the challenges associated with wind regime (capacity factor), as well as infrastructure costs (including transmission, as well as installation costs requiring major cranes) are noted to be a barrier.

A.1.4 BIOMASS

As of the 1992 Resource Plan, biomass had been studied for the generation of power in the Watson Lake region[4].

Biomass use for thermal generation is subject to the economic constraints related to the fixed costs (including fixed operating and maintenance costs). These costs do not fall dramatically for smaller scale operations or loads. In these circumstances, economic viability hinges on large and constantly running facilities.

As a general principle, biomass generation does not typically become economic unless three key conditions are met. These same conclusions have also recently been cited as preconditions for biomass electricity generation by the Alaska Energy Authority and in some cases the Yukon Cabinet Commission on Energy[5].

1. The fuel (typically wood) must be available from a source that would otherwise have to pay to dispose of it. Economic biomass generation is not typically possible with a wood product that has a cost to harvest, or even (in at least some cases) that can be delivered to the plant for free; there has to be savings from avoided disposal costs.

[4] A 6 MW steam-fired turbine had been assessed (assuming the Watson Lake sawmill was in operation) and determined to have too long a pay back period. See in particular the Yukon Cabinet Commission on Energy publication entitled “Wood”, September 1997.

[5] Wood-Fired Boilers for Rural Communities, Online: http://www.uaf.edu/aetdl/presentationsre02.html. Also the 1998 Yukon Cabinet Commission on Energy “Principles of Supply Options for the Yukon” noted “Although abundant in supply, wood is not generally seen as a cost effective way to generate electrical power unless it has little or no cost as a fuel source”.

2. The wood-fired power displaces diesel power.
3. There is a substantial market for power and heat.

To date, proposals discussed in Yukon do not meet these three key criteria.

In the Yukon, one biomass proposal received to date involves a waste wood generation facility at Haines Junction. However, that proposal was largely focused on burning wood that was previously killed by beetle infestation which will likely not be useable by the time the loads develop. A 2002 Canadian Forest Service annual Forest Health Survey found that the infestation was slowing. Standing wood tends to start to lose its heating value within three years of dying, and the bulk of the deadfall is now more than three years old.

Further information on biomass can be found in *Chapter 5: Industrial Development Scenarios and Opportunities.*

A.1.5 COAL

Coal-fired generation was examined in detail in the 1992 Resource Plan.

The economics of coal generation are very sensitive to various factors, such as the quality of the coal and emissions standards, which can materially impact the capital costs required for the plant (for example, ash handling and dealing with sulphur in the coal). The practical minimum size coal development considered for Yukon has been 20 MW which roughly equates to 144 GW.h/year.

Technologies for use of coal have been advancing at a rapid pace, particularly in regards to reducing emissions. Recent studies in Alaska have also summarized and assessed the potential for small coal developments, including Atmospheric Fluidized Bed Combustion[6]. Although a number of studies were cited, no successful small scale (1-10 MW) electrical utility coal projects are known to be in service in the north.

Key to development of environmentally sound coal generation in Yukon is the development of indigenous coal deposits independently of power generation requirements.

[6] "Galena Electric Power – a Situational Analysis" as noted above.

Further information on coal can be found in *Chapter 5: Industrial Development Scenarios and Opportunities.*

A.1.6 COAL-BED METHANE

Coal-bed methane generation was not studied in the 1992 Resource Plan.

Coal-bed methane generation produces electricity by using a methane gas from coal seams and fractures in coal beds, to produce electricity with conventional turbines. In order for coal-bed methane to be economic, the site must be close to a population base. In Yukon, no developed resources for coal-bed methane are available.

The Alaska resource study considered the potential for coal bed methane. No utility generation from coal bed methane is in service in Alaska today. The Alaska summary document identified high exploration and drilling costs, and the disposal of water as the main challenges associated with coal-bed methane generation.

A.1.7 NATURAL GAS

Natural gas was not reviewed in 1992.

Natural gas as a source for power is only available where commercial sources of gas can be delivered. Currently gas in not available in Yukon for utility purposes. Natural gas is in use in Inuvik, NWT for both domestic use (home heating) and power generation via reciprocating engines.

The availability of gas in Yukon would provide opportunities for a dramatic shift in the power resource framework for Yukon. Gas is a flexible resource that easily allows for “scalable” generation (from small 30 kW micro-turbines through massive turbines of hundred of MW, and including reciprocating engines of the size range is use in Inuvik of 2-3 MW).

However, given the limitations of gas availability in Yukon today, there is no option for gas generation to meet near-term requirements (Chapter 4) but serious investigation is required of opportunities to use gas (or maintain the option to use gas when it arrives) under Chapter 5 scenarios. If in the near-term Yukon Energy pursues new diesel generating units, consideration will be given to the potential to secure units that can later be converted to natural gas or can be run as dual fuel units.

Alaska has devoted considerable time and energy to natural gas generation given the availability of gas in many key communities. This information and experience will be of significant value to Yukon should gas become available during the period covered by the Resource Plan.

A.1.8 GEOTHERMAL

Geothermal generation was not studied in the 1992 Resource Plan.

Using heat energy from a geothermal resource is practical only if the geothermal occurrence and the energy need are located in close proximity. Thus, the development of geothermal applications in the Yukon will first occur where geothermal resources are found close to populated areas. A major well registry, mapping and resource analysis project is presently underway which will assemble the existing and available information on the groundwater and ground-source heat potential in all Yukon communities.

Known geothermal resources in the Yukon are too low in temperature to produce steam that could be used to generate electricity on a cost-competitive basis. While geothermal temperatures in the range of 100°C to 180°C are required, Yukon geothermal resources have so far been identified in only the 15°C to 55°C range. As a result, the Yukon's geothermal resources are best suited for heat energy applications such as space or district heating.

The recent reviews from Alaska noted similar concerns with respect to location of geothermal resources in relation to loads, and high capital costs of installing geothermal generation.

A.1.9 HYDROGEN

Hydrogen generation was not studied in the 1992 Resource Plan.

Yukon Energy has assessed hydrogen as an option for energy storage for electrical power. Given current hydro surpluses, the potential exists for electrolysis during off-peak or summer seasons for storage and use during peak times (or for isolated system generation or other non-utility purposes). However, given the technical complexity including issues related to storage and transportation, and the capital costs of hydrogen systems, hydrogen has not been considered a feasible resource option at this time.

Similar conclusions from Alaska indicate "feasibility is unknown, and the prospects without further advances in technology and market development are poor"[7].

A.1.10 SOLAR

Solar generation was not studied in the 1992 Resource Plan.

Given the angle of the sun, the intensity of the sunlight received closer to the Arctic Circle is less than in southern jurisdictions. Solar radiation is greater in the summer time, when there is currently a hydro surplus in the Yukon. As such, solar power does not provide any potential value to the Yukon in the near term, but has the potential to provide value in future if it is used to offset diesel generation.

Solar power is characterized by high initial or capital costs, and potentially low operating and maintenance costs. In isolated areas where grid power is not an option, residential and small commercial applications for mining camps, lodges, especially those with higher or solely summertime use, solar power may be considered a viable option.

The recent work in Alaska similarly concluded in respect of solar generation that "this technology is generally not cost-competitive for utility use when other alternatives are available"[8].

A.1.11 NUCLEAR

Nuclear generation was not studied in the 1992 Resource Plan.

Nuclear generation was studied for the Alaskan community of Galena based on a 10 MW Toshiba 4S reactor, which was to be provided for free from the manufacturer as a North American "Reference Case". Nuclear power was found to have the potential to be cost-competitive compared to diesel or coal, assuming that diesel and coal costs result in higher operating costs. The rising cost of diesel fuel has the potential to increase the economic attractiveness of nuclear generation.

The primary uncertainties with respect to nuclear power in Alaska are security and technical feasibility. In Galena, it was estimated that a minimum of four, and a maximum of 34 guards would be required. The proposed reactor is also a new technology for North America and will likely not available on a commercial basis for many years.

[7] "New Energy for Alaska" Alaska Power Association. March 2004.
[8] "New Energy for Alaska" Alaska Power Association. March 2004.

For Yukon, there is no commercial availability for the type of nuclear generation studied for Galena, and its future commercial availability is unknown. However many characteristics (size, life, efficiency, cost) of the project considered for Galena could be very attractive for consideration in Yukon. Other relevant considerations (including security and waste disposal) will clearly need substantial further attention before the true potential for nuclear in Yukon can be assessed.

A.1.12 DEMAND SIDE MANAGEMENT

DSM options were studied extensively as part of the 1992 Resource Plan Submission. In addition to the information provided in the main document, a separate binder (Demand Side: Binder B), contained detailed information on DSM options evaluated by the Utilities. The approach to DSM in 1992 reflected the situation that existed at that time; the Faro Mine was still in operation. A summary of the approach to DSM was outline at page 8 of the Demand Side Management binder, "In the Yukon, significant opportunities exist for Energy (GWh) savings because of the high cost of diesel generation. However, savings opportunities through reduction in peak Demand (MW) are relatively small due to the low capital cost for installing new diesel generation facilities. The priority, therefore, for DSM programs in the Yukon at this time relates to strategic reduction in energy use." Given the closure of the Faro Mine, there is no longer an incentive to decrease annual energy use. Consequently, the focus of the 1992 DSM plan does not correspond with Yukon Energy's current needs.

Yukon has been actively and aggressively engaged in DSM activities of various types since 1992, and in particular since 2000. Major emphasis from entities such as ESC, YDC and Natural Resources Canada has focused on reducing loads on isolated diesel systems, reducing non-electrical energy consumption (such as oil heating) as well as major efforts by Yukon Energy to grow the WAF loads via Secondary Sales (with surplus hydro, the most pertinent WAF DSM programs focus on selling this renewable resource that would otherwise be wasted, rather than reducing consumption).

In the near-term in Yukon, the electrical system requirements are almost entirely related to peak capacity (Chapter 4). Most non-industrial DSM programming is generally more successful at energy reductions than capacity reductions. As such, DSM has limited potential to address utility requirements in the near-term. In addition, DSM activities in the near-term that lower peak demand levels, but reduce utility sales which are currently being made from surplus hydro will be an adverse rate driver in Yukon (as lost revenue from reduced sales will outweigh cost savings from reduced system peaks).

Over the longer term, and under the various industrial scenarios (Chapter 5), DSM activities have the potential to contribute to savings from diesel fuel generation. As such, DSM activities will in all likelihood become an important utility focus should such scenarios arise. However, as a major supply option, there are limits to the scale of savings available from DSM. For example, under the 25 MW scenario diesel consumption on WAF proceeds rapidly to more than 100 GW.h per year – given a current firm non-industrial WAF sales of 250 GW.h/year, it is not possible for DSM to provide the resources needed to address this scenario, and therefore major displacement of diesel must come from supply-side resources (such as new hydro generation).

Information on Yukon DSM is provided in greater detail in *Section 2.4.5: Demand Side Management and the Energy Solutions Centre.*

A.2 LITERATURE REVIEWED

A.2.1 HYDRO

BC Hydro's 2002 Small Hydro Assessment in Yukon and northern BC.

Yukon Economic Development. Yukon Energy Resources: Hydro. March 1997.

The article provided an overview of hydro generation in Yukon, and issues affecting development. The article indicated that facilities smaller than 20 MW as the most likely to succeed.

A.2.2 WIND

Yukon Development Corporation & Yukon Energy Corporation. The Winds of Change: The Story of Wind . Generation in the Yukon. March 2001.

The report summarizes the history of wind generation in the Yukon and the history of Yukon Energy's experimental turbines at Haeckel Hill. YEC installed Bonus 150 kW MARK III in 1993 at Haeckel Hill in 1993. However, the report indicates that even with the special modifications that had been made to the Bonus before it was installed, there are still some problems, especially the lower temperatures and rime icing. The capacity factor of the turbine is 21%. The Vestas V47-660 kW was installed in 2000. YEC forecast a capacity factor of 23% for the Vestas.

Yukon Economic Development. Yukon Energy Resources: Wind. March 1997.

The article provides an overview of wind development in Yukon, and factors affecting development. The report indicates that wind velocities are greater at higher elevations; and that wind has the greatest velocities in the winter months, correlating with the period of peak electrical demand. However, rime icing is a significant factor impacting reliability and production levels during the winter peak.

A.2.3 BIOMASS

Wood-Fired Boilers for Rural Communities, Online: http://www.uaf.edu/aetdl/presentationsre02.html

Yukon Economic Development. Yukon Energy Resources: Wood. March 1997.

The article provided an overview of Yukon's wood fuel resources and the factors affecting development. The report indicated that wood fuel is a source of residential heating fuel, and supports existing small industries in sawmilling and firewood cutting. Further potential for wood fuel, including limited export and as a means of producing electricity were also identified.

A.2.4 COAL

Yukon Economic Development. Yukon Energy Resources: Coal. March 1997.

The article provides an overview of Yukon's coal resources, and the factors impacting development. The local markets identified for coal, included power generation and industrial heating.

A.2.5 LITERATURE REVIEWED ASSESSING MULTIPLE GENERATION TECHNOLOGIES

A number of publications were reviewed that provided an overview of generation and/or demand side management options for the Territory. These publications are outlined below.

New Energy for Alaska. Alaska Power Association. March 2004.

The publication includes an examination of a number of alternative energy sources, including: battery energy storage systems; biomass power; clean coal; coal bed methane; cogeneration; diesel engine efficiency; fuel cells; geothermal; hydroelectric power; hydrogen; microturbines; solar; tidal energy; and wind turbines. Given the similarities between Alaska and the Yukon, the analysis provided relevant comparisons for the Yukon.

Galena Electric Power – a Situational Analysis (Draft Final Report). Prepared for the U.S. Department of Energy. December 2004.
The economics of electrical power generation options for the City of Galena, Alaska were identified. Given the similarities between Alaska and the Yukon, the analysis provided relevant comparisons for the Yukon.

Economic Development from Renewable Energy: Yukon Opportunities. Provided by Pembina Institute. October 1999.
The report summarizes the energy conservation and efficiency, key renewable energy resources, and their application in the Yukon. The economic benefits, environmental and social aspects of renewable energy, and strategic direction for renewable energy in the Yukon were examined.

Yukon Government Cabinet Commission on Energy. Energy Efficiency for the Yukon, 1998.
The report provided an overview of the potential for greater energy efficiency in the Yukon.

Yukon Government Cabinet Commission on Energy. Green Power Fund. 1998.
The report provided an overview of a Green Power Fund for the Yukon.

Yukon Government Cabinet Commission on Energy. Principles of Supply Options for the Yukon, 1998.
The report provided an overview of principles of supply options for the Yukon.

Yukon Economic Development. Yukon Energy Resources: Alternatives. March 1997.
Generation resources were identified and examined, including: solar energy, geothermal energy and refuse-derived energy.

Yukon Economic Development. Yukon Energy Resources: Oil & Gas. March 1997.
The article provides an overview of oil and gas generation in the Yukon, and the factors affecting their development. The article explored development activities, and environmental issues.

APPENDIX B:
HYDRO PROJECT OPTIONS

B.1 HYDRO PROJECT OPTIONS

Yukon Energy has developed an inventory of many potential hydro sites in Yukon and in northern BC that have been studied in the past (primarily by NCPC or Government of Canada, and reviewed from time to time by Yukon Energy). Based on the inventory of sites studied in the past, Appendix B reviews specific potential hydro sites over a range of sizes.

The projects in this chapter reflect the primary alternatives identified to date based on review of the numerous studies conducted in Yukon. In selecting the projects noted in this chapter, location was used as a key screening factor, as well as information available on the relative attractiveness of the various sites (as reflected in part in the rough qualitative and quantitative factors considered in the various Level 1 work on the projects, including potential integrated system benefits).

Rough assumptions to date are that hydro projects in the 1-4 MW range cannot support any material transmission costs beyond simple connection (i.e., must be basically on the established transmission, preferably 138 kV) while 5-10 MW projects may be able to support transmission of 50 km (to perhaps as high as 100 km at a maximum). Projects in the 10-30 MW range may be able to allow for transmission somewhat over 100 km.

For the large to very large projects (30-60 MW and 60+ MW) there has not been any serious effort to screen based on incremental transmission costs, as this can only likely be usefully considered once loads have been identified and required upgrades or additional circuits to existing transmission can be incorporated into the assessment – such planning is not possible in the absence of further information about potential loads.

No screening is applied in this section based on environmental or socio-economic considerations. Such considerations would become key considerations for projects that can progress through an initial “technical” screening of the type outlined in this Appendix and Chapter 5.

The hydro sites reviewed in this Appendix are summarized in Table B-1 and shown on the map in Figure B-1.

Table B-1:
Potential Hydro Sites

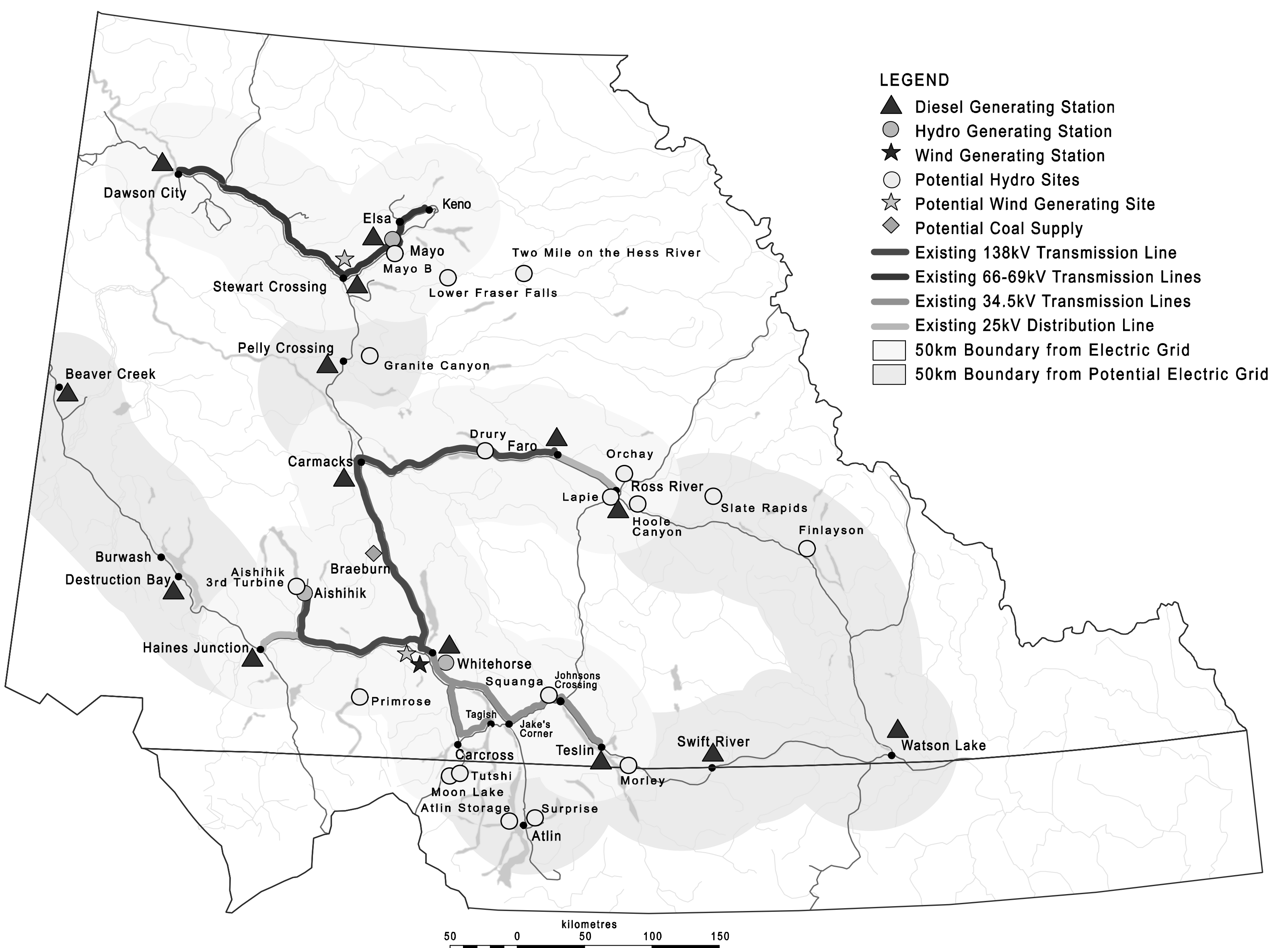
	Grid	Installed MW	GWh	Capital Cost (2005$millions) (excl. trans.)	Trans. Distance (km)	Protected under Yukon land claims	In BC	Capital Cost LCOE (cents/KWh) excl. trans (2005$ real)
Existing Hydro Enhancements								
Aishihik Diversions	WAF	0	total of 24	n/a	0	X		n/a
Atlin Storage	WAF	2	9	n/a	0		X	n/a
Very Small Hydro Projects (1-4 MW)								
Drury	WAF	2.6	23	31	0	X		7.2
Squanga	WAF	1.75	8.3	12	5			7.7
Orchay	WAF	4.2	27	47	15			9.2
Morley	WAF	4	22	31	30	X		7.5
Lapie	WAF	2	10	14	8			7.4
Small Hydro Projects (5-10 MW)								
Moon	WAF	8.5	50	51	66		X	5.4
Surprise	WAF	8.5	50	50	100		X	5.3
Tutshi	WAF	7.5	50	79	25		X	8.4
Mayo B	MD	10	48	101	0			11.2
Medium Hydro Projects (10-30 MW)								
Primrose	WAF	28	141	191	100			7.2
Finlayson	WAF	17	129	179	230			7.4
Large Hydro Projects (30-60 MW)								
Hoole	WAF	40	275	412	100			8.0
Slate	WAF	42	252	422	172			8.9
Two Mile Canyon on the Hess	MD	53	280	380	n/a	X		7.2
Very Large Hydro Sites (60+ MW)								
Granite	WAF	80 (up to 250)	660	706	125	X		5.7
Fraser Falls	MD	100 (up to 450)	613	555	n/a			4.8
Yukon River *(such as Rink Rapid, Eagles Nest, Five Fingers)*	WAF	various 75-240	n/a	n/a	n/a			n/a

Many of the above hydro projects arise from studies carried out by NCPC prior to 1987. In many cases these projects have not been subsequently reviewed in sufficient detail to confirm technical, economic or environmental acceptability for Yukon Energy to pursue today.

The above table also notes that some of the potential hydro projects identified here are “protected” under the Yukon First Nations land claims. Protection under the land claims agreements does not preclude the requirement to consult and work with local First Nations should Yukon Energy determine a need to develop these projects to supply load requirements. Furthermore, the extent to which such “protection” in each case may or may not extend to the elevations required to reach the maximum outputs noted in this Appendix has not yet been confirmed (because, as noted, further work has not yet been carried out since the initial studies).

Figure B-1:
Map of Potential Supply Options

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL SUPPLY OPTIONS



HCFUTUREGRIDEXTENSIONLOADMAP.DGN V2 Jan. 2006

B.1.1 LEVELIZED COST OF ENERGY

A primary consideration in screening potential new projects is the basic generation cost of energy supplied by output from any new resource (with typical focus on overall unit cost per kW.h as opposed to cost per MW of capacity). For the purposes of initial screening, "levelized costs of energy" ("LCOE") can be used to determine the unit costs/kW.h at the project site of energy produced. Levelized costs reflect the costs of the plant amortized over its life (all kW.h units available to be produced by the plant) assessed on real dollar (2005$) economic terms (i.e., assuming the levelized unit cost after 2005 increases with inflation each year).

- LCOE focuses only on key generation cost components for a resource option as needed to screen or compare alternative resource options during preliminary assessment stages[1].
- LCOE for hydro supply projects accordingly focuses in most instances only on capital costs, as these tend to establish the primary overall generation cost for this option[2]. Operating and maintenance costs for large projects can be quite modest (0.5% of capital cost based on BC Hydro estimates) which would tend to increase the LCOE by about 9.4%. Smaller hydro project operating and maintenance costs may vary up to 1.0% to 1.5% of capital cost, which can increase LCOE by 18.8% to 28.3% over the levels quoted in Table B-1.
- In the case of other resource options which involve material fuel operating costs (e.g., diesel generation, or thermal generation using coal, wood biomass or natural gas) it is also necessary that the LCOE reflect fuel as well as capital costs (if the capital costs are also likely to be a key part of the option's overall costs).
- LCOE automatically takes into consideration variations in the economic lives of alternative resource options.
- LCOE implicitly assumes that all energy generated over the economic life of a resource option is sold at rates that fully recover the LCOE costs, i.e., this screening tool does not address the extent to which a resource option may be oversized to meet forecast loads, or otherwise mismatched with forecast loads (in terms of, say, seasonal consideration).

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[1] In BC, transmission costs to interconnect a project are considered in the levelized costing, but not overall transmission system upgrades required outside of the simple connection to the generation. In Yukon, screening of hydro projects is intended to be a quick and relatively simple process, so transmission costs to interconnect stations are not specifically estimated but are approximated in the screening process by focusing, for each scale of project, on only those projects a reasonable distance from developed transmission systems.

[2] Hydro project operating costs are modest compared to capital costs (outside of special charges such as BC water rentals, which need to be separately considered).

Levelized cost of energy as it is used in this Resource Plan for hydro focuses exclusively on hydro capital costs (excluding transmission and excluding O&M), estimated in 2005$ (includes 25% for owner's costs and contingency). Levelized costs are calculated by dividing the 2005$ capital cost of the project by a 65 year energy output (kW.h) of the project, discounted each year at a real discount rate of 5.41%. The real discount rate is determined by a nominal discount rate of 7.52% (based on YEC's costs of capital – 40% equity at 9.05% and 60$ debt at 6.5%) and inflation of 2%[3].

B.2 EXISTING HYDRO ENHANCEMENTS

Opportunities to enhance existing hydro in Yukon include items identified in Chapter 4 (such as re-runnering, Aishihik 3rd Turbine, Marsh Lake Top Storage and other potential opportunities in the Southern Lakes) as well as the Aishihik Diversions projects.

B.2.1 AISHIHIK DIVERSIONS

One set of projects that Yukon Energy has protected under the First Nations land claims (Champagne and Aishihik First Nation and Kluane First Nation as required) is the potential diversion of Long Lake (maximum 4.6 GW.h), Hutshi Creek (maximum 1.8 GW.h) and Gladstone Lake (maximum 17.7 GW.h) into the Aishihik Lake and Canyon Lake systems (total maximum potential energy of 24.0 GW.h per year). These projects have the potential to add energy with no new capacity Considerable further work would be required on these project before their respective feasibility can be assessed, including work to update capabilities and considerations with respect to licencing.

B.2.2 ATLIN STORAGE

NCPC studied and assessed the potential to optimize the water regime on Atlin Lake (an important upstream source of water for the existing Whitehorse Rapids hydro plant) to allow improved winter flows on the Yukon River. Although various potential scales exist, one option involves managing the lake within the natural range. This variant is expected to be able to provide 2.0 MW of enhanced Whitehorse Rapids firm capacity, plus 9 GW.h of additional energy (depending on loads). No reliable updated cost estimates

[3] This is generally consistent with major utilities considering long-term generation options. Other LCOE approaches have been used at times by other utilities when comparing to IPP projects, which attempt to address disparities in the length of IPP contracts compared to project service lives, the availability of low-cost financing to Crown utilities compared to IPPs, before-tax versus after-tax costs of Crown utilities versus IPPs, and elimination of federal government subsidies that may distort economic choices and fail to recognize that subsidies are a cost to taxpayers (see, for example, the 2005 BC Hydro Resource Options Report, section 4), The intent of such processes is to incorporate "societal perspectives" rather than focus on ratepayer perspectives. The Yukon Energy Resource Plan focuses primarily on utility and ratepayer perspectives.

are available, and significant complications are expected with respect to required interprovincial licencing processes should the project be advanced.

B.3 VERY SMALL PROJECTS (1-4 MW)

Very small hydro projects in the range of 1-4 MW may be candidates for development under Chapter 5 forecasts under the 10 MW industrial scenario or larger (at the very maximum that the 10 MW scenario can handle).

B.3.1 DRURY

Drury is a proposed 2.6 MW, 23 GW.h project that capitalizes on the head between Drury Lake and the confluence of Drury Creek with Little Salmon Lake. Drury was assessed in 1992, and remains the preferred candidate for scenarios with capacity and energy requirements consistent with Drury's output. The project has a capital cost of $31 million (2005$).

On a simple LCOE basis the costs of Drury are about 7.2 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes.

The 2.6 MW is a firm winter capacity number based on the assumption that the plant would be developed to operate at a very high load factor throughout the year (e.g., include all necessary storage to allow firm winter supplies). If a more variable and flexible operating regime were to be considered for Drury, additional capacity above 2.6 MW could be installed (larger capacity configurations up to 5.2 MW and 29 GW.h have also been recently considered, at a cost of $37 million – a gain of 2.6 MW and about 6 GW.h). Alternate project layouts and sizes must be evaluated to determine the optimum scheme.

The plant would interconnect with the 138 kV line which follows the highway from Carmacks to Faro and would give rise to very little transmission costs.

Yukon Energy has the Drury site protected under the Yukon First Nation land claims agreements.

B.3.2 SQUANGA

A small potential site at Squanga Creek, at 1.75 MW and 8.3 GW.h at a rough capital cost of $12 million for a run-of-river version (2005$). This creek is near Johnson's Crossing with a steep final drop into the Teslin River, where the project would be located. Yukon Energy did work on Squanga as part of the 1992

Resource Plan, focusing on a run-of-river design with primarily summer supply (only 500 kW of firm winter capacity). In 1992 the potential for year-round storage was also noted, but little recent study of the potential for this variation had taken place.

The simple LCOE of Squanga is about 7.7 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes.

In 1996 during the call for Expressions of Interest, Yukon Energy received an IPP proposal to develop Squanga at a similar run-of-the-river (limited winter capacity) configuration. Since that time, Yukon Energy/Yukon Development have been approached by private IPP developers interested in developing the Squanga site and YDC worked with one private outfit (via the Green Power Fund) with respect to further work. Continuing issues with Squanga relate to its limited ability as studied to provide winter capacity, and its location on a weak transmission link (the 34.5 kV system towards Teslin).

B.3.3 MORLEY, LAPIE AND ORCHAY

Three other sites in this size range that were recommended by the YUB for further water monitoring in 1992 (but not further assessment work) were Morley (past Teslin, 4 MW, 22 GW.h, $31 million (2005$)), Lapie (near Ross river, 2 MW, 10 GW.h, $14 million (2005$)) and Orchay (near Ross River, 4.2 MW, 27 GW.h, $47 million (2005$)). In each case, YEC has conducted water monitoring, but not undertaken the additional work required to advance the projects to the level of Drury in terms of technical assessment. In each case, projects may be limited by transmission, as they are not located on or near the 138 kV system.

Simple LCOE for these projects (excluding transmission, incremental operating and maintenance costs and taxes) varies from 7.4 cents/kW.h (Lapie) to 7.5 cents/kW.h (Morley) to 9.2 cents/kW.h (Orchay) (2005$, real).

Yukon Energy has the Morley site protected under the Yukon First Nation land claims agreements.

B.4 SMALL PROJECTS (5-10 MW)

Small hydro projects in the range of 5-10 MW may be candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger. These projects may also be part of a development plan under the larger 40 MW scenario.

B.4.1 MOON HYDRO SITE

The proposed Moon Lake project would have a capacity of 8.5 MW with 50 GW.h of annual generation at an estimated capital cost of $51 million (2005$). Potential exists for increasing the energy capability by the diversions of other small watersheds into Moon Lake. Additionally, the capacity could be increased to take greater advantage of the seasonal storage capability (other versions of Moon have been cited at as large as 14.6 MW for primarily winter peaking operation).

The simple LCOE of Moon is about 5.4 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes (also excludes water rentals – see below).

Moon Lake is located in northern BC on the east shore of Tutshi Lake, approximately 45 km south of Carcross, Yukon. Moon Lake provides the opportunity for seasonal storage of water (like Aishihik) focused on allowing summer flows to be stored for use during the winter. Due to the distance from the 138 kV transmission grid (about 66 km), a reasonably substantial amount of new transmission would be required[4].

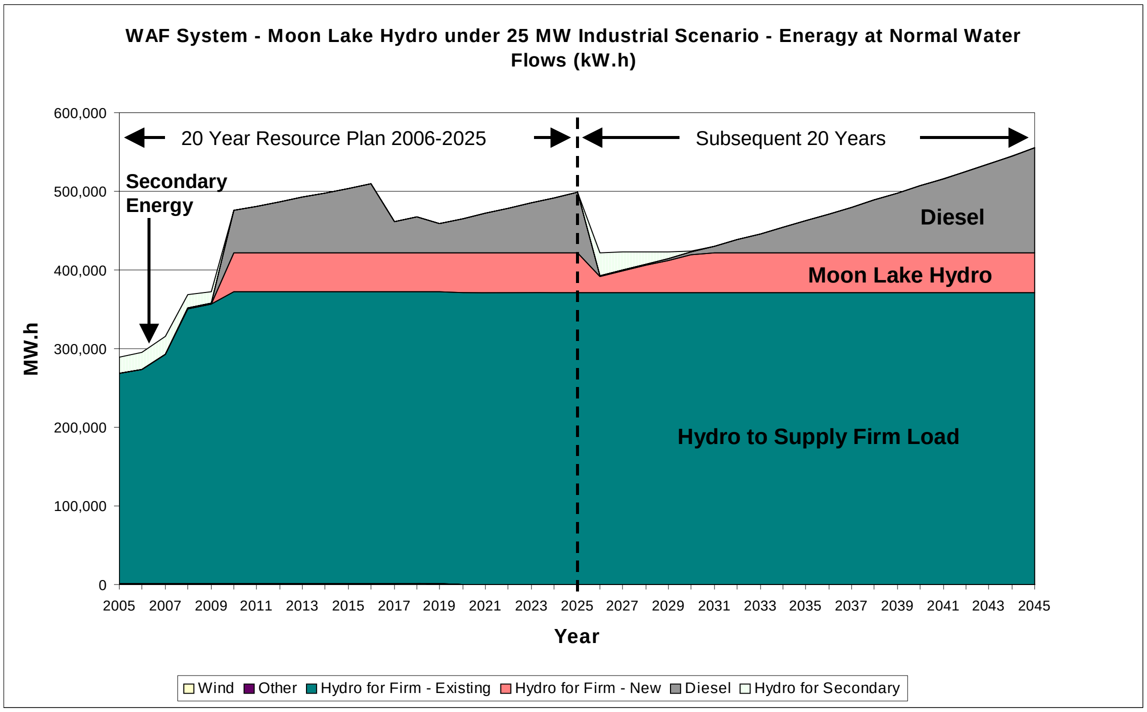
Because the Moon Lake project is located in BC, it would be subject to economic disadvantages due to material "water rental" payments and potentially property and school taxes that would be due to the BC government, as well as potentially more complicated licencing and regulations. The economic feasibility of operating in BC would need to be thoroughly assessed before proceeding with this project. Water rental payments to the BC government, for example, can likely add in the range of 0.5 cents/kW.h to the LCOE of the project.

In 1996, during the call for Expressions of Interest, Yukon Energy received a proposal from a local developer to either develop Moon Lake for Yukon Energy, or to develop the project as an IPP.
If developed in response to the 25 MW Industrial Development Scenario 2 (see Chapter 5: Section 5.2.2), it will become relevant to consider in detail the load fit of Moon to the loads to be developed. Under the 25 MW scenario loads, Moon would see full use of its energy output through 2045, with the exception of the 2026-2029 period (when surplus Moon hydro would arise, from 22 GW.h in 2026 reducing to 6 GW.h

[4] Although this transmission connection has not been priced, at a standard pricing of about $130,000 per km, plus substations, the rough capital cost could equate to $10 million. If this transmission line is solely providing a connection to Moon, the extra costs could increase the LCOE by 1.1 cents/kW.h

in 2029) as noted in Figure B-2. The impact of this 4 year surplus energy period is an increase in the LCOE of Moon over 65 years from 5.4 cents/kW.h (if all output could be used) to 5.6 cents/kW.h[5].

Figure B-2:
WAF Energy Requirements under 25 MW Scenario with Moon Lake Hydro



B.4.2 SURPRISE LAKE HYDRO SITE

In 1992, Surprise Lake was considered one of the key options for Yukon Energy in this size range. It was studied extensively in the early 1990's and a joint venture was contemplated with YEC, YECL and Synex to develop the project. It is an 8.5 MW project (50 GW.h) in two powerhouses estimated at $50 million (2005$).

In earlier review, significant concerns arose with respect to transmission requirements (more than 100 km from Jake's Corner to the site near Atlin, plus issues related to the 34.5 kV connection to Jake's Corner), regulatory requirements (due to location in BC), and economics due to material "water rental" payments and property and school taxes that would be due to the BC government as well as the local community.

[5] Full screening of Moon under a 25 MW scenario could therefore result in LCOE of 5.6 cents/kW.h for hydro capital costs reflecting "load fit", plus about 18.8% for hydro O&M based on 1% of capital cost (reflecting small projects, about $500,000 per year (2005$)), plus 1.1 cents/kW.h for transmission, plus 0.5 cents/kW.h for BC water rentals (ignoring taxes) for a total LCOE of 8.25 cents/kW.h (2005$, real).

More recently, the local community has indicated they are proceeding with a much smaller variant of the project to supply power solely to BC Hydro at Atlin. This development would likely preclude any future development of the full project as contemplated by Yukon Energy, and the project has been discarded by Yukon Energy as a likely development for Yukon needs.

B.4.3 TUTSHI AND OTHER HYDRO SITES IN THE SOUTHERN LAKES

There are a number of sites in the southern lakes that may provide opportunities for new generation, such as on the Tutshi River (7.5 MW installed, 50 GW.h, $79 million (2005$), LCOE of 8.4 cents/kW.h[6] plus water rentals to BC government). These projects serve to provide new generation as well as potentially enhance management of flow to the existing Whitehorse Rapids plant which provides added generation benefits (both capacity and energy). Yukon Energy is currently undertaking a hydrology study of this area along with site identification of potential water management structures or generating stations. Until that work is complete, all potential generation projects remain at the very initial stages of study.

Similar to Moon, a development of Tutshi under the 25 MW scenario would give rise to at least four years of surplus energy from 2026-2029. However, the actual annual flow patterns, flexibility and storage potential of Tutshi (and its associated impacts on Whitehorse Rapids) have not been recently assessed, and it is possible that surplus hydro would arise for more than four years if the plant output is not as able to be tailored to fit WAF loads as a Moon or other existing flexible resources such as Aishihik. The impact on LCOE from this surplus hydro under optimum conditions (a very flexible output from Tutshi) is an increase from 8.4 to 8.6 cents/kW.h; however the impact could be considerably more under a less flexible output.

B.4.4 MAYO B

The existing hydro site at Mayo has the potential to be enhanced by various changes in configuration, either to develop further head below the existing reservoir or an expansion of capacity utilizing the same head. This leads to multiple potential alternatives. However, as a supply option to WAF, these various projects are only of relevance if the Carmacks-Stewart transmission line is previously in service. The full capability of various potential Mayo enhancements to supply an interconnected WAF and MD system (as opposed to MD on its own) has not been fully studied, and should be re-examined in the event that the interconnection proceeds.

[6] As above, excludes transmission, incremental operating and maintenance costs and taxes.

One configuration alternative considered is a 10 MW, 48 GW.h, $101 million (2005$) variation based on a separate conveyance route from the existing reservoir to a new plant lower in elevation than the existing plant, which would be able to operate in parallel with the existing plant. This concept has an initial LCOE of 11.2 cents/kW.h. Various other concepts require further study. However, although work is still in preliminary stages, it must be recognized that it is possible no credible facility enhancements of this type exist at Mayo.

B.4.5 LACK OF OTHER YUKON-BASED HYDRO PROJECTS

There are very limited other potential hydro projects in the broad 5-15 MW size range identified in Yukon (as opposed to BC). One is near Faro, involving a diversion of the Anvil Creek and Rose Creek (9 MW, 70 GW.h, no reliable recent cost estimates available). Other identified projects are in the vicinity of Ross River (Prevost Canyon) or Pelly Crossing (Mica Creek) but have little to no reliable updated assessment of capital costs, transmission constraints and other key feasibility variables. Given the economic disadvantages of projects in BC (due to water rentals and taxes), it would be beneficial to secure generating station options in Yukon.

B.5 MEDIUM PROJECTS (10-30 MW)

Medium sized hydro projects have potential fit to the 40 MW industrial development scenario. However, key limitations arise with respect to the requirement for projects of this size once the mines close, as well as the risks of premature mine closures.

B.5.1 PRIMROSE/KUSAWA/TAKHINI HYDRO SITE

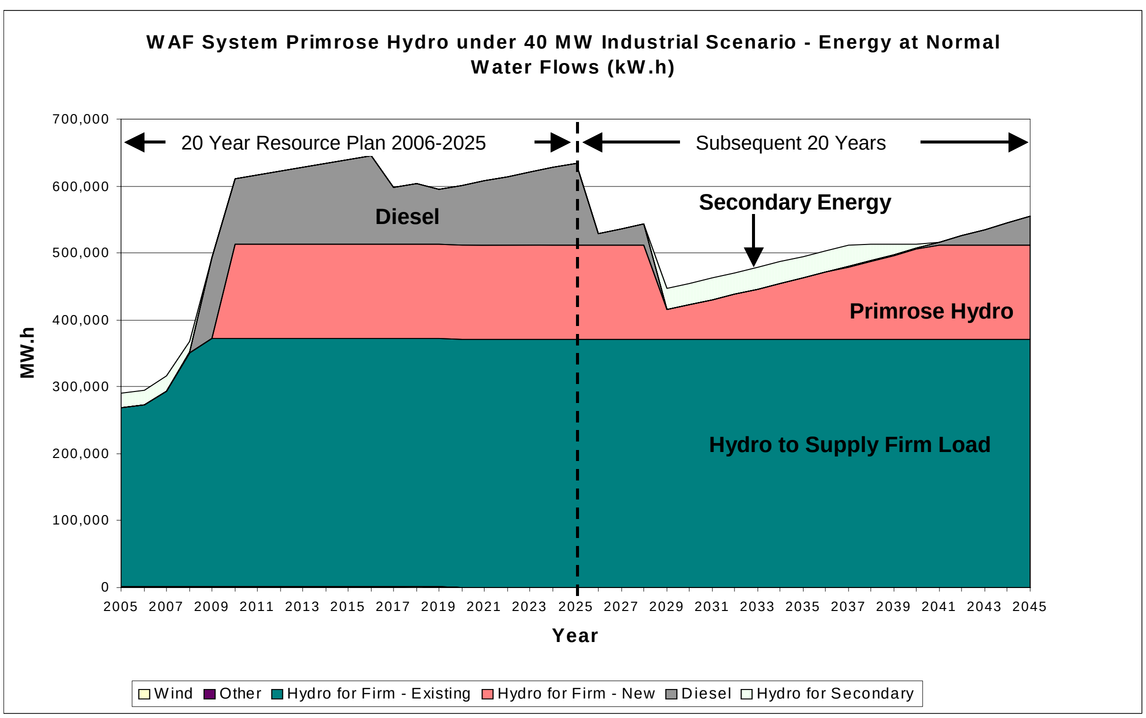
The potential Primrose generating station involves a number of potential concepts that were studied as alternatives to the Aishihik GS when it was constructed (studied in 1962, 1968, 1975, some more recent reviews). In general terms, the project involves developing hydro generation to capture the head between the high elevation Primrose Lake or Rose Lake and either Kusawa Lake or Takhini Lake.
Variations considered to date extend from about 19 MW to 30 MW and 100 to 180 GW.h. The primary concept reviewed to date is 28 MW, 141 GW.h/year estimated at $191 million (2005$). The LCOE under this scenario, consistent with the approaches used above, is about 7.2 cents/kW.h (2005$, real).

The site has reasonable access to developed transmission (less than 100 km, potential impact on LCOE of about 0.5 cents/kW.h). However, the site is located within an area that may be encompassed by a Park or special conservation area (subject to ongoing discussions with Yukon Government and the Kwanlin Dun, Champagne and Aishihik, and Carcross Tagish First Nations), which may limit development opportunities. Primrose is not "protected" by notation under the Yukon First Nations land claim agreements. In addition, the Primrose River is glacial fed and carries large amounts of silt, which may pose technical problems for a generating station.

The project is located in Yukon, so would not be subject to economic disadvantages of BC locations due to "water rental" payments or property and school taxes, as well as the potentially more complicated interprovincial licencing regulations.

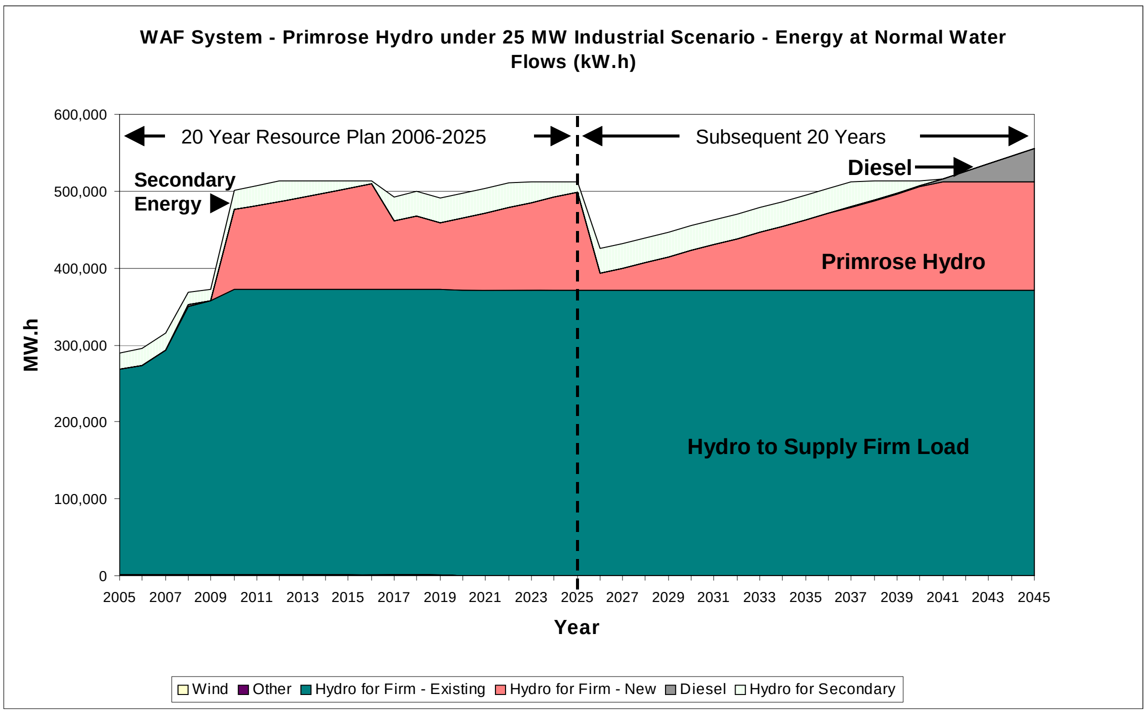
The key issues with Primrose or other hydro sites under the 40 MW scenario is the lack of load following closure of the mines, and the resulting potential for material surplus energy at that time (and potential consequent adverse rate impacts) as noted in Figure B3. In particular, were Primrose to be developed to service the 40 MW Industrial Scenario 3 (see Chapter 5: Section 5.2.3), its output would be fully utilized from the date of in-service to 2028. Starting in 2029 the facility would be in excess of WAF needs (about 2/3 of its output would be surplus), and the hydro surplus would extend through 2040. The consequent impact on project LCOE over 65 years is an increase from 7.2 to 7.7 cents/kW.h.

Figure B-3:
WAF Energy Requirements under 40 MW Scenario with Primrose Hydro



In contrast, were Primrose to be brought into service under the 25 MW industrial scenario, as noted in Figure B-4, the size would be well in excess of the system requirements in many years, and the consequent impact on LCOE would be an increase from about 7.2 cents/kW.h to over 9.0 cents/kW.h.

Figure B-4:
WAF Energy Requirements under 25 MW Scenario with Primrose Hydro



B.5.2 FINLAYSON HYDRO SITE

This potential project is on the Finlayson River, at Frances Lake well past Ross River near the Robert Campbell highway. It is potentially a 17 MW generating station (very high load factor, at 129 GW.h/year), and has a substantial transmission requirement (about 230 km). No recent reviews have been done of the potential costs of the station, but simple escalations from earlier capital cost estimates indicate potentially $179 million (2005$) (equivalent to an LCOE of 7.4 cents/kW.h in 2005$, real).

Finlayson is located in the Kaska area which has not signed a final agreement, so the status of any protection is not available.

Other larger hydro generating sites also exist in this area, along with significant future mining potential (Wolverine, Kudz Ze Kayah, others) which may enable a major system development along the Robert

Campbell highway at some point in the future. However, as a lone supply option, Finlayson is unlikely to be economic due to the substantial transmission requirements (which could add more than 1.2 cents/kW.h to the above LCOE).

B.6 LARGE PROJECTS (30-60 MW)

Large sized hydro projects have limited potential under any of the industrial load scenarios, with the exception of potential service to a limited number of compressors under the Alaska highway pipeline case.

B.6.1 HOOLE

Hoole is located on the Pelly River east of Ross River and is in the Kaska First Nations area which does not have final agreement on any protection for potential hydro sites. The project is a 40 MW, 275 GW.h/year facility at an estimated $412 million capital cost (2005$). Resulting LCOE is 8.0 cents/kW.h (2005$, real).

B.6.2 SLATE

Slate is similarly on the Pelly River east of Ross River, and is also in the area without final agreements as yet on protected sites (Kaska). The project is a 42 MW, 252 GW.h/year facility at an estimated $422 million capital cost (2005$). The resulting LCOE is 8.9 cents/kW.h (2005$, real))

B.6.3 HESS

Two Mile Canyon on the Hess is located east of Mayo and is protected in the Yukon land claims agreements. It is only of value to WAF if Stewart-Carmacks interconnection in place. The project is a 53 MW, 280 GW.h/year with an estimated $380 million capital cost (2005$). The resulting LCOE is 7.2 cents/kW.h (2005$, real)).

B.7 VERY LARGE PROJECTS (60 MW+)

Very large hydro projects have the potential to service most or all of the potential Alaska highway pipeline loads.

B.7.1 GRANITE CANYON

On the Pelly River (east of Pelly Crossing), Granite Canyon is a site that was studied by NCPC under a number of different concepts and sizes. Although the site is protected under the Yukon final agreements, the extent to which development of the site can be accommodated within the “protection” areas has not yet been determined. Possible development concepts previously studied range from 80 MW (660 GW.h/year and $706 million capital cost (2005$)) or up to 250 MW or more. The LCOE is about 5.7 cents per kW.h (2005$, real) for the 80 MW version excluding transmission.

B.7.2 FRASER FALLS

On the Stewart River east of Mayo, possible concepts range from 100 MW up to 450 MW; the smallest version (100 MW, 613 GWh/year) has been estimated (2005$) to cost about $555 million, with LCOE for generation at about 4.8 cents per kW.h (2005$, real), excluding transmission costs.

B.7.3 VARIOUS OTHER LARGE YUKON RIVER SITES

Other sites have been identified on the Yukon River, well downstream of Whitehorse, ranging from 100 MW to 500 MW. No costs are available at this time for these options.

APPENDIX C:
AISHIHIK 3RD TURBINE ASSESSMENT

C.1 AISHIHIK 3RD TURBINE ASSESSMENT

Yukon Energy has reviewed the economics of a potential Aishihik 3rd turbine project under various assumptions, focused on a 65 year life. The assessment reviews five cases, as summarized in Chapter 4:

- **Section C-2:** Aishihik 3rd Turbine at 2009 under Base Case Loads

- **Section C-3:** Aishihik 3rd Turbine at 2009 under Base Case with 10 MW Mine Loads

- **Section C-4:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case Loads

- **Section C-5:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case with 10 MW Mine Loads

- **Section C-6:** Aishihik 3rd Turbine at 2011 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case Loads

- **Section C-7:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage and (2008) of Carmacks-Stewart (CS) under Base Case with 10 MW Mine Loads

In each case, there are two sets of tables presented:

- **Overall Project Economics (IRR based on cash flows):** The first indicates an overall cash flow analysis of the project, focused on determining the Internal Rate of Return (IRR) of the project (e.g., focused on one-time capital costs rather than "accounting" costs of depreciation or return on rate base used for ratemaking). This is basically the equivalent of the analysis of the Mayo-Dawson Transmission Line project provided in Table 5.4 of the YEC 2005 Required Revenues and Related Matters Application.
- **Ratepayer Impacts (NPV based on annual impacts on ratepayers):** The second table indicates the overall project lifetime NPV, the project NPV during the period of the current Resource Plan (2006-2025) and the annual impacts on ratepayers.

In each case, the economics do not include assessment of the expected beneficial impacts on secondary sales, particularly in the early years of the project[1].

A summary of the cases is provided in Table C1.

[1] Once the WAF system grows to the point of having "diesel on the margin" and no annual surplus hydro, all secondary sales will be interrupted, so no further impacts on secondary sales will occur as a result of the project; for a few years prior to the point of diesel on the margin, the 3rd Turbine project may also reduce the availability of secondary sales, as there will be less "surplus" hydro due to the 3rd Turbine allowing more of the water to be used to avoid peaking diesel.

Table C-1:
Summary of Aishihik 3rd Turbine Assessment Cases (2005$, $000s)

	IRR lifetime (%)	Ratepayer Costs/(Savings) (NPV) lifetime	Ratepayer Costs/(Savings) (NPV) 20 years	Years until beneficial rate impact
Section C2: Turbine in 2009 – Base Case Loads	10.81%	(4,075)	57	8
Section C3: Turbine 2009 – Base Loads with 10 MW Mines	16.31%	(7,854)	(3,722)	2
Section C4: Turbine 2009 – Base Loads – Marsh Lake Storage in service	9.95%	(3,104)	1,028	9
Section C5: Turbine 2009 – Base Loads with 10 MW Mines – Marsh Lake Storage in service	14.44%	(6,726)	(2,594)	3
Section C6: Turbine 2011 – Base Loads – Marsh Lake Storage in service	10.96%	(3,779)	291	7
Section C7: Turbine 2009 – Base Loads with 10 MW Mines – Marsh Lake Storage and Carmacks-Stewart in service	14.91%	(7,258)	(3,126)	3

1
C.2 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE LOAD

2
Table C-2A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forcast

3

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	177	177	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	279	279	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	399	-	(399)	3.48	115	115	81	7	not assessed	87	7,577	76	7,653	7,565
2010	-	-	-	3.9	-	547	-	(547)	3.48	157	157	113	10	not assessed	122	-	77	77	(45)
2011	-	-	-	3.9	-	741	0	(741)	3.48	213	213	156	13	not assessed	169	-	79	79	(90)
2012	-	-	-	3.9	-	999	42	(957)	3.48	275	275	205	18	not assessed	223	-	80	80	(143)
2013	-	-	-	3.9	-	1,341	126	(1,215)	3.48	349	349	266	23	not assessed	289	-	82	82	(207)
2014	-	-	-	3.9	-	1,786	230	(1,556)	3.48	447	447	347	30	not assessed	377	-	84	84	(293)
2015	-	-	-	3.9	-	2,352	351	(2,002)	3.48	575	575	456	39	not assessed	495	-	85	85	(409)
2016	-	-	-	3.9	-	3,055	493	(2,562)	3.48	736	736	595	51	not assessed	646	-	87	87	(559)
2017	-	-	-	3.9	-	3,909	674	(3,236)	3.48	930	930	766	66	not assessed	832	-	89	89	(743)
2018	-	-	-	3.9	-	4,926	911	(4,015)	3.48	1,154	1,154	970	83	not assessed	1,053	-	91	91	(963)
2019	-	-	-	3.9	-	6,116	1,228	(4,889)	3.48	1,405	1,405	1,205	103	not assessed	1,308	-	92	92	(1,216)
2020	-	-	-	3.9	-	7,488	1,646	(5,843)	3.48	1,679	1,679	1,469	126	not assessed	1,595	-	94	94	(1,500)
2021	722	-	(722)	3.9	185	8,327	2,186	(6,141)	3.48	1,765	1,950	1,740	151	-	1,891	-	96	96	(1,794)
2022	7,299	1,899	(5,400)	3.9	1,385	3,506	970	(2,537)	3.48	729	2,114	1,924	178	-	2,101	-	98	98	(2,003)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	-	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	34,845	29,445	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	42,053	36,653	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	49,394	43,994	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	56,871	51,471	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	64,486	59,086	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	72,242	66,842	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	80,142	74,742	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	88,188	82,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	96,383	90,983	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,729	99,329	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,230	107,830	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	121,888	116,488	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	130,706	125,306	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	139,687	134,287	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	148,835	143,435	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	158,151	152,751	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	167,640	162,240	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	177,305	171,905	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	187,148	181,748	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	197,174	191,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											10,246	947		11,193	5,669	1,068	6,738	(4,455)
																Internal Rate of Return			**10.81%**

Table C-2B: Aishihik 3rd Turbine Economics (65 years) - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	115	81	7	not assessed	87	117	565	76	758	670
2010	157	113	10	not assessed	122	117	557	77	750	628
2011	213	156	13	not assessed	169	117	548	79	743	574
2012	275	205	18	not assessed	223	117	539	80	736	513
2013	349	266	23	not assessed	289	117	530	82	729	440
2014	447	347	30	not assessed	377	117	522	84	722	345
2015	575	456	39	not assessed	495	117	513	85	715	220
2016	736	595	51	not assessed	646	117	504	87	708	62
2017	930	766	66	not assessed	832	117	495	89	701	(131)
2018	1,154	970	83	not assessed	1,053	117	487	91	694	(360)
2019	1,405	1,205	103	not assessed	1,308	117	478	92	687	(621)
2020	1,679	1,469	126	not assessed	1,595	117	469	94	680	(915)
2021	1,950	1,740	151	-	1,891	117	460	96	673	(1,218)
2022	2,114	1,924	178	-	2,101	117	451	98	666	(1,435)
2023	1,385	1,285	123	-	1,409	117	443	100	659	(750)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		10,246	947		11,193	1,236	4,813	1,068	7,118	(4,075)
7.52%								20 year NPV (2006-2025)		57

C.3 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-3A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															**Project Costs**			**Net Costs**
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	380	380	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	2,874	2,874	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	3,574	601	(2,973)	3.48	854	854	601	51	not assessed	653	7,577	76	7,653	7,000
2010	3,834	-	(3,834)	3.9	983	563	784	221	3.48	(64)	919	660	64	-	724	-	77	77	(646)
2011	9,209	3,809	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,014	97	-	1,111	-	79	79	(1,032)
2012	14,684	9,284	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	-	1,133	-	80	80	(1,053)
2013	20,428	15,028	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	-	1,156	-	82	82	(1,074)
2014	26,107	20,707	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	31,892	26,492	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	37,784	32,384	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	5,558	1,074	(4,484)	3.48	1,289	1,289	1,062	91	-	1,153	-	89	89	(1,064)
2018	-	-	-	3.9	-	6,809	1,432	(5,377)	3.48	1,545	1,545	1,299	111	-	1,411	-	91	91	(1,320)
2019	-	-	-	3.9	-	6,116	1,228	(4,889)	3.48	1,405	1,405	1,205	103	-	1,308	-	92	92	(1,216)
2020	-	-	-	3.9	-	7,488	1,646	(5,843)	3.48	1,679	1,679	1,469	126	-	1,595	-	94	94	(1,500)
2021	722	-	(722)	3.9	185	8,327	2,186	(6,141)	3.48	1,765	1,950	1,740	151	-	1,891	-	96	96	(1,794)
2022	7,299	1,899	(5,400)	3.9	1,385	3,506	970	(2,537)	3.48	729	2,114	1,924	178	-	2,101	-	98	98	(2,003)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	-	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	34,845	29,445	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	42,053	36,653	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	49,394	43,994	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	56,871	51,471	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	64,486	59,086	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	72,242	66,842	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	80,142	74,742	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	88,188	82,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	96,383	90,983	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,729	99,329	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,230	107,830	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	121,888	116,488	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	130,706	125,306	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	139,687	134,287	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	148,835	143,435	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	158,151	152,751	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	167,640	162,240	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	177,305	171,905	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	187,148	181,748	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	197,174	191,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,689	1,283		14,972	5,669	1,068	6,738	(8,234)
																Internal Rate of Return			**16.31%**

Table C-3B: Aishihik 3rd Turbine Economics (65 years) - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	854	601	51	not assessed	653	117	565	76	758	105
2010	919	660	64	-	724	117	557	77	750	27
2011	1,385	1,014	97	-	1,111	117	548	79	743	(368)
2012	1,385	1,034	99	-	1,133	117	539	80	736	(397)
2013	1,385	1,054	101	-	1,156	117	530	82	729	(427)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	1,289	1,062	91	-	1,153	117	495	89	701	(453)
2018	1,545	1,299	111	-	1,411	117	487	91	694	(717)
2019	1,405	1,205	103	-	1,308	117	478	92	687	(621)
2020	1,679	1,469	126	-	1,595	117	469	94	680	(915)
2021	1,950	1,740	151	-	1,891	117	460	96	673	(1,218)
2022	2,114	1,924	178	-	2,101	117	451	98	666	(1,435)
2023	1,385	1,285	123	-	1,409	117	443	100	659	(750)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		13,689	1,283		14,972	1,236	4,813	1,068	7,118	(7,854)
7.52%								20 year NPV (2006-2025)		(3,722)

C.4 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS

Table C-4A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	45	45	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	125	125	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	221	-	(221)	3.48	64	64	45	4	not assessed	49	7,577	76	7,653	7,604
2010	-	-	-	3.9	-	333	-	(333)	3.48	96	96	69	6	not assessed	74	-	77	77	3
2011	-	-	-	3.9	-	466	-	(466)	3.48	134	134	98	8	not assessed	106	-	79	79	(27)
2012	-	-	-	3.9	-	635	-	(635)	3.48	182	182	136	12	not assessed	148	-	80	80	(67)
2013	-	-	-	3.9	-	858	17	(840)	3.48	241	241	184	16	not assessed	200	-	82	82	(118)
2014	-	-	-	3.9	-	1,155	89	(1,066)	3.48	306	306	238	20	not assessed	258	-	84	84	(175)
2015	-	-	-	3.9	-	1,546	189	(1,357)	3.48	390	390	309	26	not assessed	336	-	85	85	(250)
2016	-	-	-	3.9	-	2,051	305	(1,746)	3.48	502	502	406	35	not assessed	440	-	87	87	(353)
2017	-	-	-	3.9	-	2,687	440	(2,247)	3.48	646	646	532	46	not assessed	578	-	89	89	(489)
2018	-	-	-	3.9	-	3,471	606	(2,864)	3.48	823	823	692	59	not assessed	751	-	91	91	(661)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	not assessed	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	not assessed	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	not assessed	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	not assessed	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											9,355	867		10,222	5,669	1,068	6,738	(3,484)
																Internal Rate of Return			**9.95%**

Table C-4B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	64	45	4	not assessed	49	117	565	76	758	709
2010	96	69	6	not assessed	74	117	557	77	750	676
2011	134	98	8	not assessed	106	117	548	79	743	637
2012	182	136	12	not assessed	148	117	539	80	736	588
2013	241	184	16	not assessed	200	117	530	82	729	529
2014	306	238	20	not assessed	258	117	522	84	722	463
2015	390	309	26	not assessed	336	117	513	85	715	379
2016	502	406	35	not assessed	440	117	504	87	708	267
2017	646	532	46	not assessed	578	117	495	89	701	123
2018	823	692	59	not assessed	751	117	487	91	694	(58)
2019	1,032	885	76	not assessed	961	117	478	92	687	(274)
2020	1,270	1,111	95	not assessed	1,206	117	469	94	680	(527)
2021	1,534	1,368	117	not assessed	1,486	117	460	96	673	(813)
2022	1,818	1,655	142	not assessed	1,796	117	451	98	666	(1,130)
2023	1,952	1,813	169	-	1,981	117	443	100	659	(1,322)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		9,355	867		10,222	1,236	4,813	1,068	7,118	(3,104)
7.52%								20 year NPV (2006-2025)		1,028

C.5 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-5A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	207	207	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	1,919	1,919	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	2,435	387	(2,048)	3.48	589	589	414	35	not assessed	450	7,577	76	7,653	7,203
2010	-	-	-	3.9	-	3,060	518	(2,541)	3.48	730	730	524	45	not assessed	569	-	77	77	(492)
2011	1,509	-	(1,509)	3.9	387	2,293	680	(1,613)	3.48	464	851	623	56	-	679	-	79	79	(600)
2012	6,984	1,584	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	-	1,133	-	80	80	(1,053)
2013	12,728	7,328	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	-	1,156	-	82	82	(1,074)
2014	18,407	13,007	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	24,192	18,792	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	30,084	24,684	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	3,969	718	(3,251)	3.48	934	934	770	66	-	836	-	89	89	(747)
2018	-	-	-	3.9	-	4,975	962	(4,012)	3.48	1,153	1,153	969	83	-	1,053	-	91	91	(962)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	-	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	-	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	-	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	-	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											12,663	1,181		13,844	5,669	1,068	6,738	(7,106)
																Internal Rate of Return			**14.44%**

C-5B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	589	414	35	not assessed	450	117	565	76	758	308
2010	730	524	45	not assessed	569	117	557	77	750	182
2011	851	623	56	-	679	117	548	79	743	64
2012	1,385	1,034	99	-	1,133	117	539	80	736	(397)
2013	1,385	1,054	101	-	1,156	117	530	82	729	(427)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	934	770	66	-	836	117	495	89	701	(135)
2018	1,153	969	83	-	1,053	117	487	91	694	(359)
2019	1,032	885	76	-	961	117	478	92	687	(274)
2020	1,270	1,111	95	-	1,206	117	469	94	680	(527)
2021	1,534	1,368	117	-	1,486	117	460	96	673	(813)
2022	1,818	1,655	142	-	1,796	117	451	98	666	(1,130)
2023	1,952	1,813	169	-	1,981	117	443	100	659	(1,322)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		12,663	1,181		13,844	1,236	4,813	1,068	7,118	(6,726)
7.52%								20 year NPV (2006-2025)		(2,594)

C.6 AISHIHIK 3RD TURBINE AT 2011 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS

Table C-6A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	45	45	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	125	125	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	221	221	-	3.48	-	-	-	-		-	-	-	-	-
2010	-	-	-	3.9	-	333	333	-	3.48	-	-	-	-		-	-	-	-	-
2011	-	-	-	3.9	-	466	-	(466)	3.48	134	134	98	8	not assessed	106	7,883	79	7,962	7,856
2012	-	-	-	3.9	-	635	-	(635)	3.48	182	182	136	12	not assessed	148	-	80	80	(67)
2013	-	-	-	3.9	-	858	17	(840)	3.48	241	241	184	16	not assessed	200	-	82	82	(118)
2014	-	-	-	3.9	-	1,155	89	(1,066)	3.48	306	306	238	20	not assessed	258	-	84	84	(175)
2015	-	-	-	3.9	-	1,546	189	(1,357)	3.48	390	390	309	26	not assessed	336	-	85	85	(250)
2016	-	-	-	3.9	-	2,051	305	(1,746)	3.48	502	502	406	35	not assessed	440	-	87	87	(353)
2017	-	-	-	3.9	-	2,687	440	(2,247)	3.48	646	646	532	46	not assessed	578	-	89	89	(489)
2018	-	-	-	3.9	-	3,471	606	(2,864)	3.48	823	823	692	59	not assessed	751	-	91	91	(661)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	not assessed	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	not assessed	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	not assessed	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	not assessed	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
2074			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,529	339	-	3,868	-	274	274	(3,593)
2075			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,600	346	-	3,945	-	280	280	(3,665)
PV (2005)	7.52%											9,320	864		10,184	5,102	962	6,064	(4,120)
																Internal Rate of Return			**10.96%**

Table C-6B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	-	-	-		-	-	-	-	-	-
2010	-	-	-		-	-	-	-	-	-
2011	134	98	8	not assessed	106	121	588	79	788	682
2012	182	136	12	not assessed	148	121	579	80	781	633
2013	241	184	16	not assessed	200	121	570	82	773	574
2014	306	238	20	not assessed	258	121	561	84	766	508
2015	390	309	26	not assessed	336	121	552	85	758	423
2016	502	406	35	not assessed	440	121	543	87	751	311
2017	646	532	46	not assessed	578	121	534	89	744	166
2018	823	692	59	not assessed	751	121	524	91	736	(15)
2019	1,032	885	76	not assessed	961	121	515	92	729	(232)
2020	1,270	1,111	95	not assessed	1,206	121	506	94	722	(485)
2021	1,534	1,368	117	not assessed	1,486	121	497	96	714	(771)
2022	1,818	1,655	142	not assessed	1,796	121	488	98	707	(1,089)
2023	1,952	1,813	169	-	1,981	121	479	100	700	(1,281)
2024	1,385	1,311	126	-	1,437	121	470	102	693	(744)
2025	1,385	1,337	128	-	1,466	121	461	104	686	(780)
2026	1,385	1,364	131	-	1,495	121	451	106	679	(816)
2027	1,385	1,391	134	-	1,525	121	442	108	672	(853)
2028	1,385	1,419	136	-	1,555	121	433	110	665	(891)
2029	1,385	1,448	139	-	1,587	121	424	113	658	(929)
2030	1,385	1,477	142	-	1,618	121	415	115	651	(967)
2031	1,385	1,506	145	-	1,651	121	406	117	644	(1,006)
2032	1,385	1,536	147	-	1,684	121	397	119	637	(1,046)
2033	1,385	1,567	150	-	1,717	121	388	122	631	(1,087)
2034	1,385	1,598	153	-	1,752	121	378	124	624	(1,128)
2035	1,385	1,630	157	-	1,787	121	369	127	617	(1,169)
2036	1,385	1,663	160	-	1,822	121	360	129	611	(1,212)
2037	1,385	1,696	163	-	1,859	121	351	132	604	(1,255)
2038	1,385	1,730	166	-	1,896	121	342	135	598	(1,298)
2039	1,385	1,765	169	-	1,934	121	333	137	591	(1,343)
2040	1,385	1,800	173	-	1,973	121	324	140	585	(1,388)
2041	1,385	1,836	176	-	2,012	121	315	143	579	(1,433)
2042	1,385	1,873	180	-	2,052	121	306	146	572	(1,480)
2043	1,385	1,910	183	-	2,093	121	296	149	566	(1,527)
2044	1,385	1,948	187	-	2,135	121	287	152	560	(1,575)
2045	1,385	1,987	191	-	2,178	121	278	155	554	(1,624)
2046	1,385	2,027	195	-	2,222	121	269	158	548	(1,674)
2047	1,385	2,068	198	-	2,266	121	260	161	542	(1,724)
2048	1,385	2,109	202	-	2,311	121	251	164	536	(1,775)
2049	1,385	2,151	207	-	2,358	121	242	167	530	(1,827)
2050	1,385	2,194	211	-	2,405	121	233	171	524	(1,880)
2051	1,385	2,238	215	-	2,453	121	223	174	519	(1,934)
2052	1,385	2,283	219	-	2,502	121	214	178	513	(1,989)
2053	1,385	2,328	224	-	2,552	121	205	181	508	(2,044)
2054	1,385	2,375	228	-	2,603	121	196	185	502	(2,101)
2055	1,385	2,422	233	-	2,655	121	187	188	497	(2,158)
2056	1,385	2,471	237	-	2,708	121	178	192	491	(2,217)
2057	1,385	2,520	242	-	2,762	121	169	196	486	(2,276)
2058	1,385	2,571	247	-	2,817	121	160	200	481	(2,337)
2059	1,385	2,622	252	-	2,874	121	150	204	476	(2,398)
2060	1,385	2,675	257	-	2,931	121	141	208	471	(2,461)
2061	1,385	2,728	262	-	2,990	121	132	212	466	(2,524)
2062	1,385	2,783	267	-	3,050	121	123	216	461	(2,589)
2063	1,385	2,838	272	-	3,111	121	114	221	456	(2,655)
2064	1,385	2,895	278	-	3,173	121	105	225	451	(2,722)
2065	1,385	2,953	283	-	3,236	121	96	230	447	(2,790)
2066	1,385	3,012	289	-	3,301	121	87	234	442	(2,859)
2067	1,385	3,072	295	-	3,367	121	78	239	438	(2,929)
2068	1,385	3,134	301	-	3,435	121	68	244	433	(3,001)
2069	1,385	3,196	307	-	3,503	121	59	249	429	(3,074)
2070	1,385	3,260	313	-	3,573	121	50	254	425	(3,148)
2071	1,385	3,325	319	-	3,645	121	41	259	421	(3,224)
2072	1,385	3,392	326	-	3,718	121	32	264	417	(3,301)
2073	1,385	3,460	332	-	3,792	121	23	269	413	(3,379)
2074	1,385	3,529	339	-	3,868	121	14	274	409	(3,458)
2075	1,385	3,600	346	-	3,945	121	5	280	406	(3,539)
PV (2005)		9,320	864		10,184	1,112	4,332	962	6,406	(3,779)
7.52%								20 year NPV (2006-2025)		291

SECTION C-7: AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE AND (2008) OF CARMACKS-STEWART (CS) UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-7A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & Carmacks-Stewart (CS) S - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenues Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	207	207	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	2,113	2,113	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	2,685	505	(2,180)	3.48	627	627	441	38	not assess	479	7,577	76	7,653	7,174
2010	-	-	-	3.9	-	3,379	667	(2,711)	3.48	779	779	559	48	not assess	607	-	77	77	(530)
2011	-	-	-	3.9	-	4,204	873	(3,331)	3.48	957	957	701	60	not assess	761	-	79	79	(682)
2012	-	-	-	3.9	-	5,171	1,137	(4,034)	3.48	1,159	1,159	866	74	not assess	940	-	80	80	(859)
2013	5,087	-	(5,087)	3.9	1,304	1,203	1,478	275	3.48	(79)	1,225	933	90	-	1,023	-	82	82	(941)
2014	11,374	5,974	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	17,777	12,377	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	24,298	18,898	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	4,735	1,014	(3,720)	3.48	1,069	1,069	881	75	-	957	-	89	89	(868)
2018	-	-	-	3.9	-	5,905	1,357	(4,548)	3.48	1,307	1,307	1,099	94	-	1,193	-	91	91	(1,103)
2019	-	-	-	3.9	-	5,365	1,194	(4,171)	3.48	1,199	1,199	1,028	88	-	1,116	-	92	92	(1,024)
2020	-	-	-	3.9	-	6,675	1,604	(5,071)	3.48	1,457	1,457	1,275	109	-	1,384	-	94	94	(1,290)
2021	-	-	-	3.9	-	8,189	2,141	(6,047)	3.48	1,738	1,738	1,551	133	-	1,683	-	96	96	(1,587)
2022	-	-	-	3.9	-	9,913	2,827	(7,087)	3.48	2,036	2,036	1,853	159	-	2,012	-	98	98	(1,914)
2023	3,787	-	(3,787)	3.9	971	8,070	3,681	(4,388)	3.48	1,261	2,232	2,072	187	-	2,259	-	100	100	(2,159)
2024	11,339	5,939	(5,400)	3.9	1,385	2,687	-	(2,687)	3.48	772	2,157	2,042	189	-	2,231	-	102	102	(2,129)
2025	19,030	13,630	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	26,863	21,463	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,842	29,442	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	42,968	37,568	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	51,244	45,844	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	59,674	54,274	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	68,259	62,859	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	77,003	71,603	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	85,909	80,509	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	94,980	89,580	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,218	98,818	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,628	108,228	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	123,211	117,811	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	132,972	127,572	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	142,913	137,513	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	153,039	147,639	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	163,351	157,951	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	173,855	168,455	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	184,552	179,152	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	195,448	190,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	206,545	201,145	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,162	1,214		14,376	5,669	1,068	6,738	(7,638)
																Internal Rate of Return			**14.91%**

Table C-7B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage & CS - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					**Project Costs (Ratepayer Impacts)**				**Net Impacts**
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	627	441	38	not assessed	479	117	565	76	758	279
2010	779	559	48	not assessed	607	117	557	77	750	144
2011	957	701	60	not assessed	761	117	548	79	743	(17)
2012	1,159	866	74	not assessed	940	117	539	80	736	(204)
2013	1,225	933	90	-	1,023	117	530	82	729	(294)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	1,069	881	75	-	957	117	495	89	701	(256)
2018	1,307	1,099	94	-	1,193	117	487	91	694	(499)
2019	1,199	1,028	88	-	1,116	117	478	92	687	(429)
2020	1,457	1,275	109	-	1,384	117	469	94	680	(704)
2021	1,738	1,551	133	-	1,683	117	460	96	673	(1,011)
2022	2,036	1,853	159	-	2,012	117	451	98	666	(1,346)
2023	2,232	2,072	187	-	2,259	117	443	100	659	(1,600)
2024	2,157	2,042	189	-	2,231	117	434	102	652	(1,578)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		13,162	1,214		14,376	1,236	4,813	1,068	7,118	(7,258)
7.52%								20 year NPV (2006-2025)		(3,126)

GLOSSARY OF TERMS

BASELOAD DIESEL GENERATION:

Diesel generation operated to provide energy, due to a shortfall in annual energy (kW.h) from hydro (or other low variable cost generating sources).

BULK ELECTRICAL SUPPLY:

The generation and transmission part of an electrical grid that delivers power to the distribution system(s).

CAPACITY:

The load for which a generating unit, generating station or other electrical apparatus is rated either by the user or by the manufacturer.

COST OF SERVICE:

The total cost incurred to provide utility service, including expenses, taxes and return on investment. The cost of service may be thought of as an annual revenue requirement.

DEMAND:

The rate of flow of electricity demanded at one point in time and the maximum size (capacity) of facilities required to serve the demands of electric customers, usually expressed in kilowatts.

ENERGY:

The consumption of electricity over a period of time by customers of an electric system, usually expressed in kilowatt hours.

FIRM CAPACITY:

Capacity which is intended to have assured availability to the customers to meet all or a portion of the load requirements.

FIXED COST:

Those costs that do not vary with the number of kilowatt hours supplied. Examples would be depreciation and return on investment.

GIGAWATT:

One gigawatt equals 1,000 megawatts.

INDUSTRIAL CUSTOMER:

Defined in OIC 1995/90 as:

a) "major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer;

b) "isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer.

KILOWATT:

One kilowatt equals 1,000 watts, where a watt is an electrical unit of real power or rate of doing work. One kilowatt is equivalent to approximately 1.34 horsepower.

KILOWATT HOUR:

The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt hour equals 1,000 watt hours.

LOAD FACTOR:

The average load of a customer, a group of customers, or the system divided by the maximum load (usually expressed as a percentage). For example, assuming 48 kWh of usage for the day, the average is 48/24 or 2 kW. If the maximum capacity available is 4 kW, the load factor is 2/4 or 50%.

LOAD FORECAST:

The forecast energy and demand requirements of the customers (usually on a monthly or annual basis).

MAXIMUM CONTINUOUS RATING:

The generation output rating in megawatts that a generating unit can sustain on a continuous basis.

MEGAWATT:

One megawatt equals 1,000 kilowatts.

PEAKING DIESEL GENERATION:

Diesel generating operated over short-term periods (hours to days) to aid in meeting the peak demand (MW) for electricity, typically during daytime hours.

RE-RUNNERING:

The replacement of turbines at an existing hydro generating station with a modern, more efficient design.

RESERVE:

Excess generation capacity that is maintained to safeguard against losses of supply due to unexpected equipment failures.

RUN OF RIVER:

Hydro projects that do not have any material storage, and must generate power based on river flows at any given point in time.

SECONDARY ENERGY:

Energy sold on an interruptible basis for service to heating loads.

ACRONYMS

BES: BULK ELECTRICITY SUPPLY

DFO: DEPARTMENT OF FISHERIES AND OCEANS

DSM: DEMAND SIDE MANAGEMENT

ESC: ENERGY SOLUTIONS CENTRE

GRA: GENERAL RATE APPLICATION

IPP: INDEPENDENT POWER PRODUCER

LCOE: LEVELIZED COSTS OF ENERGY

LOEE: LOSS OF ENERGY EXPECTATION

LOLE: LOSS OF LOAD EXPECTATION

LOLH: LOSS OF LOAD HOURS

LOLP: LOSS OF LOAD PROBABILITY

MAPL: MAXIMUM ALLOWABLE PEAK LOAD

MCR: MAXIMUM CONTINUOUS RATING

MD: MAYO-DAWSON

MW: MEGAWATT

NCPC: NORTHERN CANADA POWER COMMISSION

NTPC: NORTHWEST TERRITORIES POWER CORPORATION

NWT: NORTHWEST TERRITORIES

UKHM: UNITED KENO HILL MINE

WAF: WHITEHORSE-AISHIHIK-FARO

YDC: YUKON DEVELOPMENT CORPORATION

YEC: YUKON ENERGY CORPORATION

YECL: YUKON ELECTRICAL COMPANY LIMITED

YTG: YUKON TERRITORIAL GOVERNMENT

YTWB: YUKON TERRITORIAL WATER BOARD

YUB: YUKON UTILITIES BOARD