QUESTION:

Is integrated resource planning consistent or inconsistent with the supply of least cost electricity under Section 3 (b) (III) of the Electrical Power Control Act (NL)?

RESPONSE:

The response to this question requires a legal interpretation that Messrs. Bowman and McLaren cannot provide.

Generally however, it would be normal practice for utilities to have a long-term system planning process at a minimum to aid in evaluating future resource options. It should also be noted that many vertically-integrated Crown utilities in other jurisdictions in Canada undertake some form of publicly reviewed long-term planning exercise to address the future conditions and scenarios it may face. The following examples illustrating the scope used by other utilities and jurisdictions in Canada are attached to this response:

- Yukon Energy Corporation Resource Plan Overview document – further information is available at http://www.yukonenergy.ca/about/business/2006/
- British Columbia Utilities Commission Resource Planning Guidelines (2003)

Other examples are also available, such as Manitoba Hydro's 2001 Power Resource Plan at http://www.hydro.mb.ca/regulatory_affairs/wuskwatim/presentations/nfaat/nfaat_appendices_vol2_part1b.pdf

Yukon Energy Corporation

Overview of Yukon Energy's Resource Plan Submission

June 2006

INVITATION

Yukon Energy's 20-Year Resource Plan Submission addresses major electrical generation and transmission requirements in Yukon during the 2006 to 2025 period. In response to past commitments, this Submission was filed with the Yukon Utilities Board ("YUB") on June 1, 2006 for review by the Board.

Yukon Energy invites all Yukoners to participate in review of this 20 Year Resource Plan. To assist public review, this overview summarizes the overall approach and the proposals in the full Resource Plan Submission.

Whitehorse at Dusk (Yukon Government)

The Resource Plan provides background information on Yukon power systems. The Plan also includes an overview of the forecast near term requirements for the Yukon, and longer-term requirements assuming a number of industrial development scenarios.

In the near term, the Submission's resource planning proposals address load growth, the scheduled retirement of diesel units at Whitehorse, opportunities to enhance existing facilities, and the adoption of new capacity criteria to better protect customers from outages. These proposals include major capital projects for commitment before 2009 with costs of over $3 million each.

The Submission also proposes approaches to prepare for potential longer-term industrial development, recognizing the need to balance the risk associated with planning for industrial loads with the benefits. Past experience has shown the benefits that infrastructure development and industry can bring to the Yukon.

Yukon Energy is accountable to the YUB, and ultimately to Yukoners. We face exciting and important Resource Plan issues and opportunities today, and we welcome review and comment by the YUB on the 20-Year Resource Plan.

Yukon Energy is scheduling public meetings throughout the Yukon to provide information on the Resource Plan, and to receive comments and encourage discussion on the issues, options and proposals. The dates and locations of the public meetings will be advertised in the local media.

We invite all Yukoners to participate in this review.

David Morrison, President and CEO

PREFACE

Yukon Energy has developed a Resource Plan Submission 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 Yukon Energy commitments before the year 2009 with costs of $3 million or more per project, and

b) planning activities that Yukon Energy may be required to carry out in order to start construction on other projects before 2016 related to potential major load developments.

This document provides an overview of the Resource Plan and its implications for Yukoners, and Yukon ratepayers.

Table of Contents

Cover Photo: Mayo (www.archbould.com)

Line Repairs (www.archbould.com)

1.0 INTRODUCTION

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 Territory's grids.

Capacity 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 unit breakdowns.

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

1.1 THE RESOURCE PLANNING FRAMEWORK

The Resource Plan reviews the capability of Yukon power systems to supply electrical loads today and into the future under various time horizons, industrial load scenarios, and resource supply options.

System capability assessment reflects the forecast condition of existing facilities, firm capability of these facilities at the time of winter peak loads, and capacity planning criteria that define generation capacity ("MW") adequacy and load carrying capability.

System requirements assessment forecasts capacity (MW) and energy ("kW.h") loads over the next 20 to 40 years, including consideration of loads that may need to be met under different industrial development scenarios.

New facility requirements are forecast by comparing forecast capability of installed plant and forecast system requirements, to identify shortfalls requiring new capacity or energy resources.

Resource options to meet new facility requirements on any system are identified for each load scenario.

Assessment of Resource Options involves assessment and/or screening, to the extent feasible today, based on consideration of technical feasibility (including timing), cost efficiency, reliability, risk and other relevant considerations.

Various levels of technical and costing assessments have been carried out, in some instances to the project feasibility stage. The Resource Plan process identifies preferred projects Yukon Energy can commit to develop, when appropriate, to proceed with more detailed project-specific pre-decision planning.

The Submission also 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.

20-Year Resource Plan and Decisions on Specific Projects

The following figure reviews the relationship between the 20-Year Resource Plan process, and activities leading to final Yukon Energy construction decisions on specific project opportunities identified in the Resource Plan.

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 identifies preferred projects that YEC has identified. Once preferred projects are identified, YEC can then commit to proceed with more detailed project-specific pre-decision planning.

20-Year Resource Plan and Decisions on Specific Projects

20-Year Resource Plan:
- system capability
- system requirement forecasts
- new facility requirements
- resource options
- assessment of resource options
- includes feasibility studies for some projects (level 3 for hydro)[1]
- identify preferred projects

YEC Commitment to proceed with a Project →

Pre-Decision Planning Stages for each Project [2]
- seek YUB review (projects over $3 million)[3]
- Consultation with First Nations and others
- Environmental assessment and licencing
- Arrangements with project partners (if any)
- Financing plan
- Final design, costing, and contract approach
- Tendering process to obtain final costs

YEC Decision to proceed with construction →

YEC Board of Directors

results for a specific project opportunity:
Conclusions regarding need for project and its selection as preferred alternative

results for a specific project opportunity:
Final feasibility assessment, costing and design, all required external reviews, approvals and agreements

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.

1.2 THE 1992 RESOURCE PLAN

The last Resource Plan that was submitted to the Yukon Utilities Board in 1992 was filed jointly by Yukon Energy ("YEC") and Yukon Electrical Company Limited ("YECL"). At that time, Yukon Energy was managed by Canadian Utilities, a subsidiary of ATCO, which is YECL's parent company.

The 1992 Resource Plan reflected a situation very different from the situation in the Yukon today.

In 1992, the Faro mine was in operation on the largest power system (the Whitehorse-Aishihik-Faro grid, or WAF) and consequently that system was consuming significant diesel fuel throughout the year. Diesel fuel generation was also in use in Dawson, Watson Lake and many smaller communities. As a result, the 1992 plan focused on the opportunity to build new generation and transmission to displace use of diesel fuel.

The Yukon Systems: The distinct and independent power systems in the Yukon are each served today by separate sources 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).

There also were substantial uncertainties in 1992 regarding the life of the major Faro mine load (about 25 MW and about 180 gigawatt hours/year ("GWh/yr")).

In the end, the feasibility of nearly all projects reviewed in 1992 hinged on which mine load "scenario" was going to arise, and the risks associated with the load. Due to substantial downside load or "market" risk in 1992, no projects were recommended for the WAF, Mayo, Watson Lake or Dawson systems. The Mayo-Dawson line was considered at that time, but in 1992 was not competitive with diesel fuel so was not recommended.

1.3 THE CURRENT SITUATION

The Yukon economy, and Yukon's electricity loads and systems have changed substantially since the 1992 review. Due to closure of the Faro mine, no reopening of the Keno Hill mine, and no new mines yet having emerged, there is currently a surplus of hydro energy available on the WAF and MD grids. If no major new industrial loads emerge, these WAF and MD hydro energy surpluses could remain for most or all of the current 20 year planning period.

Yukon Energy is facing a shortfall today, however, in WAF generation capacity to serve winter peak loads. This shortfall is due to pending retirement of some Whitehorse diesel units, load growth and the adoption of new capacity planning criteria.

In addition, potential new industrial developments during the next several years may absorb the WAF hydro energy surplus and create opportunities once again to develop new infrastructure.

The Resource Plan reviews the 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.

1.4 OVERVIEW OF FACTORS DRIVING FUTURE RESOURCE PLAN REQUIREMENTS

The Resource Plan takes into account the following key factors currently affecting power requirements in Yukon:

There is an immediate need for new WAF generation capacity: Forecast load growth, pending retirement of three diesel units located in YEC's Whitehorse diesel plant (11.4 MW), and new capacity criteria adopted by Yukon Energy together create an immediate need for new WAF generation capacity to serve peak winter load requirements.

Potential new mines planned for the period prior to 2009: Potential new industrial developments prior to 2009 at the Minto and Carmacks Copper mines may absorb the WAF hydro energy surplus, supporting a transmission extension of the WAF grid from Carmacks to at least Pelly Crossing and creating an opportunity to interconnect the WAF and MD grids.

A range of other longer term industrial development scenarios and opportunities may arise: Planning activities for other energy-focused generation projects beyond 2009 and before 2016 are being driven by a diverse range of possible industrial developments. This includes various mines, as well as the Alaska Highway Gas Pipeline. Supply resource options with the potential to start construction within the next 10 years to supply these loads vary widely depending on the industrial development that arises. The options include a range of different generation and transmission possibilities, including hydro, diesel, and possibly coal and/or natural gas generation. If these major industrial loads arise, demand-side management resources will also be considered.

Balance is required: Industrial loads provide the opportunity to develop hydro or other beneficial long-term generation, similar to the existing Whitehorse, Aishihik or Mayo hydro stations (or similar low-cost hydro facilities in Northwest Territories). This opportunity only arises if Yukon Energy is sufficiently prepared to develop these facilities fairly quickly once the industrial loads emerge. Spending today on planning activities must balance the potential future benefits and risks associated with such projects.

Yukon Energy's Whitehorse Rapids Facility (Derek Crowe)

1.5 LOADS, RESOURCE NEEDS AND SUPPLY OPTIONS

The types of resources required over the 20 year Resource Plan period depend on the loads expected to arise.

Loads, Resource Needs and Supply Options

Load	Needs
LARGEST LOADS **Pipeline**	**Major New Generation**
Multiple Mines **Large Mines**	**Capacity and Energy**
Small Mines **Base Loads** SMALLEST LOADS	**Capacity**

Under basic non-industrial loads (including ongoing load growth), there is only a need for new capacity resources in the planning period. With the addition of small industrial loads such as small mines (up to about 10 MW), the focus remains on new capacity at levels similar to or slightly above that required under the base loads.

Were large mines to connect to the system (similar in size to the Faro mine), opportunities for relatively modest new energy projects arise. Substantial new generation project opportunities, similar to the existing Whitehorse (40 MW) or Aishihik (30 MW) size range or larger, only arise in cases with at least multiple long-lived new mines.

The largest loads considered in the Resource Plan are those that would arise if electricity for compression purposes is used for the Alaska Highway pipeline. Under these scenarios, generation project opportunities that vastly exceed the current Yukon system arise.

The duration of the mine load can be as important as its size when it comes to resource planning.

The feasibility of new infrastructure opportunities to displace diesel generation typically requires effective use over relatively long time periods, e.g., 20 or 30 years or more. Accordingly, a large new mine load that lasts only 5 or 10 years likely will not, by itself, sustain cost effective new diesel displacing projects. In contrast, a smaller new industrial load expected to be sustained for 20 years or more may create very real opportunities for cost-effective new diesel-displacing developments.

Industry and the Development of Hydro Generation in the Yukon

Hydro generation in the Yukon was developed in the past by the Northern Canada Power Commission ("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.

1) In 1952, NCPC built the Mayo Hydro facility to supply power to Mayo and United Keno Hill Mine ("UKHM") in Elsa and Keno.

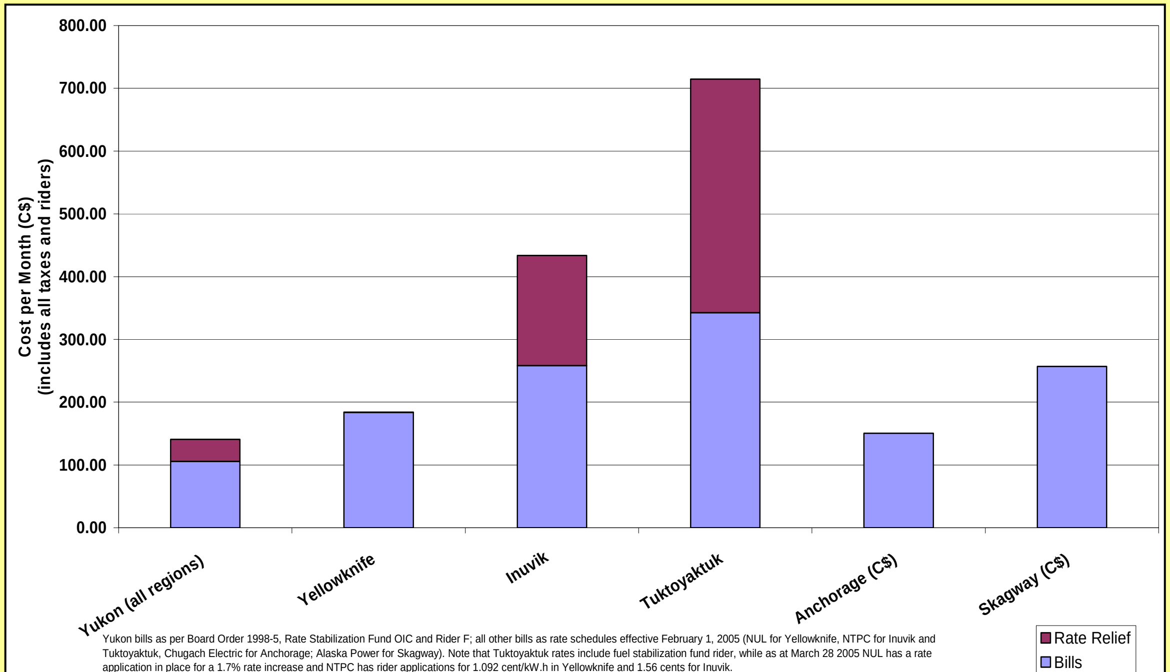
2) In 1958, NCPC built the first two turbines at Whitehorse Rapids to supply the rapidly growing demand for power in Whitehorse.

3) 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 the Government of Canada to build a mining facility at Faro.

4) 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.

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.

Residential Electricity Bills in Comparison to Yukon 2005
(1000 kW.h/month Residential Non-Government Customer)



Yukon bills as per Board Order 1998-5, Rate Stabilization Fund OIC and Rider F; all other bills as rate schedules effective February 1, 2005 (NUL for Yellowknife, NTPC for Inuvik and Tuktoyaktuk, Chugach Electric for Anchorage; Alaska Power for Skagway). Note that Tuktoyaktuk rates include fuel stabilization fund rider, while as at March 28 2005 NUL has a rate application in place for a 1.7% rate increase and NTPC has rider applications for 1.092 cent/kW.h in Yellowknife and 1.56 cents for Inuvik.

2.0 BACKGROUND ON YUKON POWER SYSTEMS

Yukon Energy is the main bulk electrical supply provider (main generator and transmitter) of electrical energy in Yukon, currently accounting for 90% of annual Yukon power generation. This section provides an overview of Yukon power systems.

2.1 OVERVIEW OF TRANSMISSION AND GENERATION FACILITIES IN YUKON

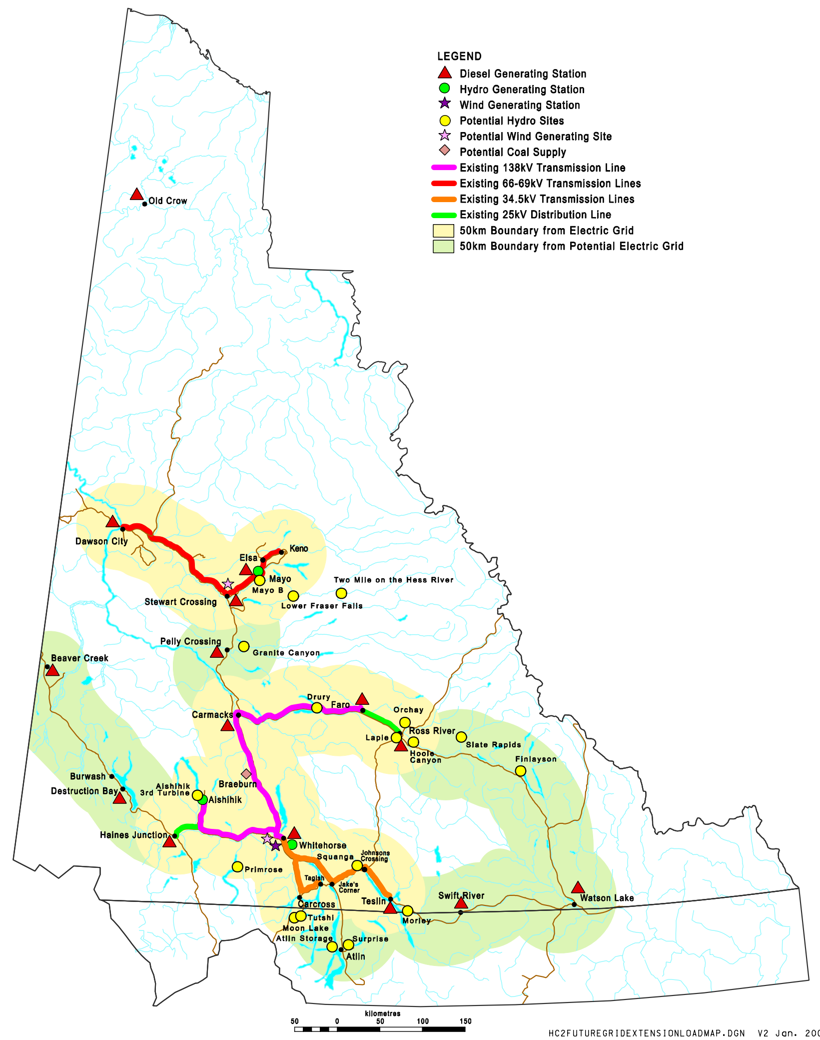
Yukon Energy currently serves approximately 1,700 retail customers, or 11%, of Yukon's customers directly. The retail customers that are served directly include residential and commercial classes. The majority of these customers are located in and around Dawson City, Mayo, and Faro.

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 generation, as well as its distribution lines, independent of Yukon Energy.

Transmission: Yukon Energy owns and operates Yukon's two independent higher voltage (69 kV or higher) WAF and MD transmission systems in Yukon. Some lower voltage lines (25 to 34.5 kV) are also owned and operated by YECL.

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.

Existing Territorial Power Infrastructure and Potential Supply Options



The MD system is composed of a 223 kilometre 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.

Contractors Constructing the Mayo-Dawson Transmission Line (www.archbould.com)

Generation: Hydro generation from the Aishihik and Whitehorse stations supplies the WAF communities of: Carmacks, Carcross, Haines Junction, Teslin, Whitehorse, Ross River, Tagish, Deep Creek, Takhini River 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), and on a wholesale basis to YECL for service to Stewart Crossing, Elsa, and Keno.

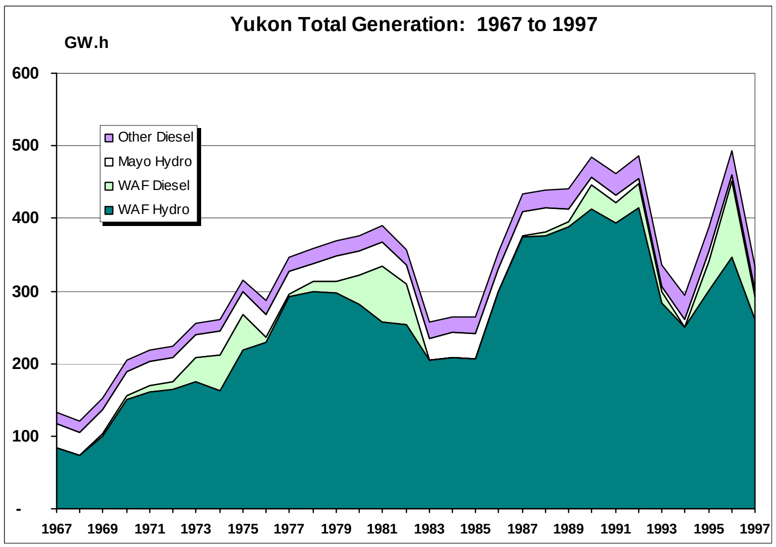
Hydro generation stations on the Yukon grids are supplemented as necessary by a small amount of diesel for peaking or maintenance purposes, and on the WAF grid by wind generation. The absence of power grid interconnections with other neighbouring jurisdictions prevents export of surplus generation or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

Generation Capacity in Yukon – YEC and YECL in 2005
Total Yukon Power Generation

Yukon Energy Generation Assets (in MW installed & current 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)			

The overall importance of 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-1990s is shown in the figure below. This figure also demonstrates the relatively minor effect overall for Yukon related to diesel generation required outside the WAF and Mayo areas.

Yukon Total Power Generation 1967 – 1997

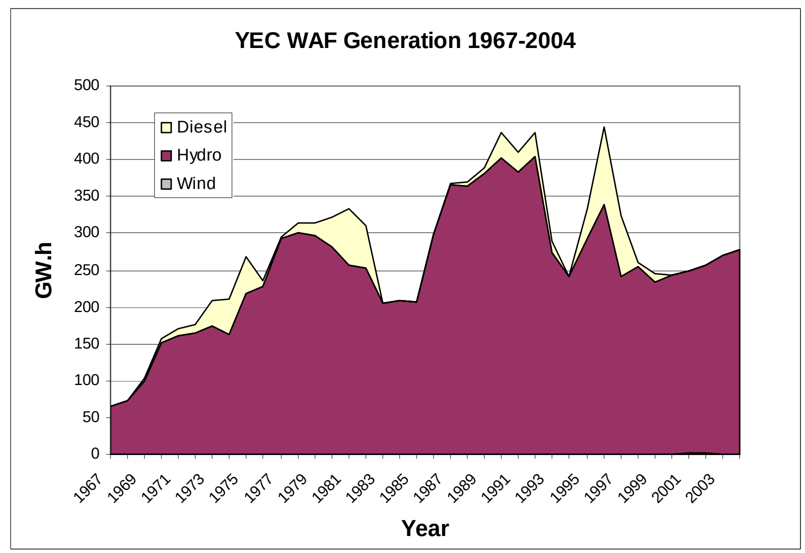


"GW.h" are millions of kilowatt hours. Generation data is provided to 1997, which is the last year of complete generation data that YEC has on record. In 1997 YEC transferred to direct management, and YEC and YECL data are no longer integrated.

WAF Generation

The figure below 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. During periods of Faro shutdowns (1983-1986, 1993-1995, part of 1997, and 1998 onwards) the system requirements have been well below the hydro capability. In an average year of water flows, the current WAF system can supply about 358 GW.h of energy (approximately 90 GW.h of this today is surplus hydro energy and not reflected in current generation).

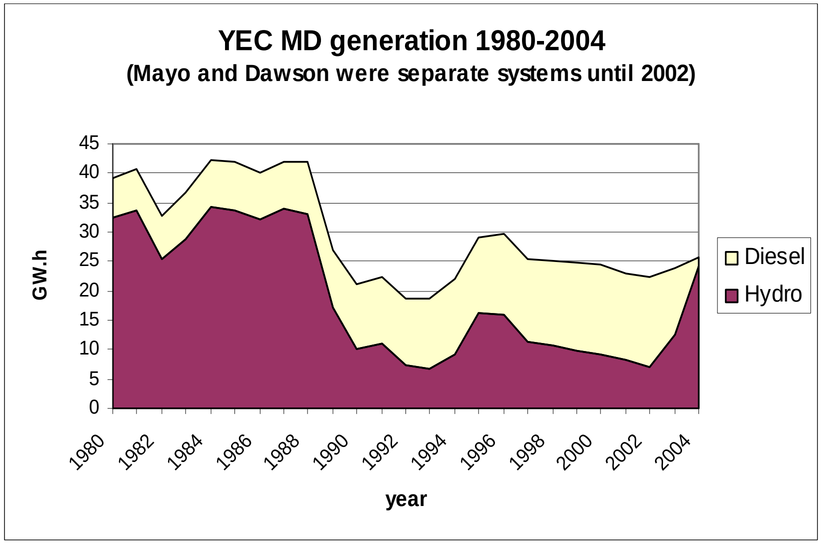
YEC WAF Generation 1967 – 2004



MD Generation

The figure below 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. The annual energy capability of the Mayo hydro station under long-term average water flows is 42 GW.h, well above current loads of about 25 GW.h/year.

Generation on MD, 1980 to 2004



2.2 MAJOR EVENTS SINCE THE 1992 RESOURCE PLAN

Several major events have contributed since 1992 to increased flexibility related to resource planning. The closure of the Faro mine for example, led to the growth of secondary sales. The renewal of water licences at all three Yukon Energy hydro generating stations has paved the way for enhancements at these facilities. Recent construction of the Mayo-Dawson line has highlighted the economic benefits and flexibility that come from system integration.

2.2.1 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 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.

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

Since the final closure of the Faro Mine in 1998, there has generally been a hydro energy surplus on WAF.

2.2.2 The Growth of Secondary Sales

Before the NCPC transfer, Secondary Energy had been available from time to time to General Service or Industrial customers based on the availability of surplus hydro.

Rate Schedule 32 – Secondary Energy, provides Yukon Energy with an opportunity to sell excess low-cost hydro power under terms where YEC can interrupt secondary sales customers whenever it is likely that the utility will be required to generate electricity with diesel. Secondary energy typically displaces space or process heating that would otherwise be provided by an alternative fuel source. The current Secondary Energy rate was set out in YUB Board Order 2005-12. The rate was set at 66.7% of the price of fuel oil, adjusted every three months.

Secondary sales have grown from 3.9 GW.h in 2000 to a forecast 20.6 GW.h/year for 2005, primarily on WAF. Surplus hydro generation on the MD grid also allows for growth in secondary sales on that system.

There are now approximately 25 retail customers who together receive more than 20 GW.h of electricity under this rate. These customers use the electricity to displace fuel oil, and in some cases, propane.

At today's rates, Secondary Energy sales are very beneficial to the system, as they generate more than $1 million of extra revenues annually at very little extra cost. However, for the purposes of planning the system for capacity requirements or energy projects, secondary service is not included as a required load to be served.

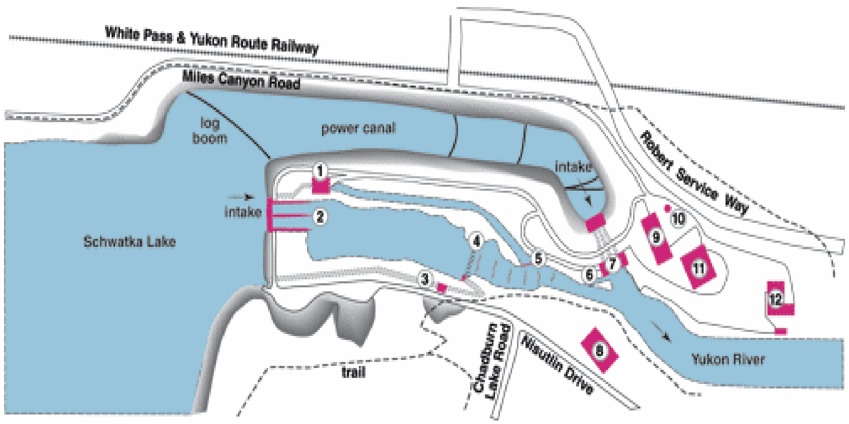
In some cases the ability to enhance sales of secondary power can provide added economic benefits from certain projects. For example, since the completion of the Mayo-Dawson line, excess hydro power generated in Mayo can now be sold to new Secondary Energy customers in Dawson.

2.2.3 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 the three facilities have expired since the 1992 Resource Plan filing, and each licence has been renewed.

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.



Whitehorse Rapids Facility

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. The licence renewal was granted by the YTWB on this basis.

Dam safety monitoring requirements were formalized in the new licence, similar to Whitehorse.

Aishihik: Relicencing of the Aishihik hydroelectric facility took place over a number of years. It involved four amendments to the 1978 licence and required Yukon Energy to secure a federal Fisheries Act Authorization. The new licence was issued in 2002 for a 17-year period.

Similar to Whitehorse and Mayo, the dam safety requirements in the licence are normal modern utility standards. 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.

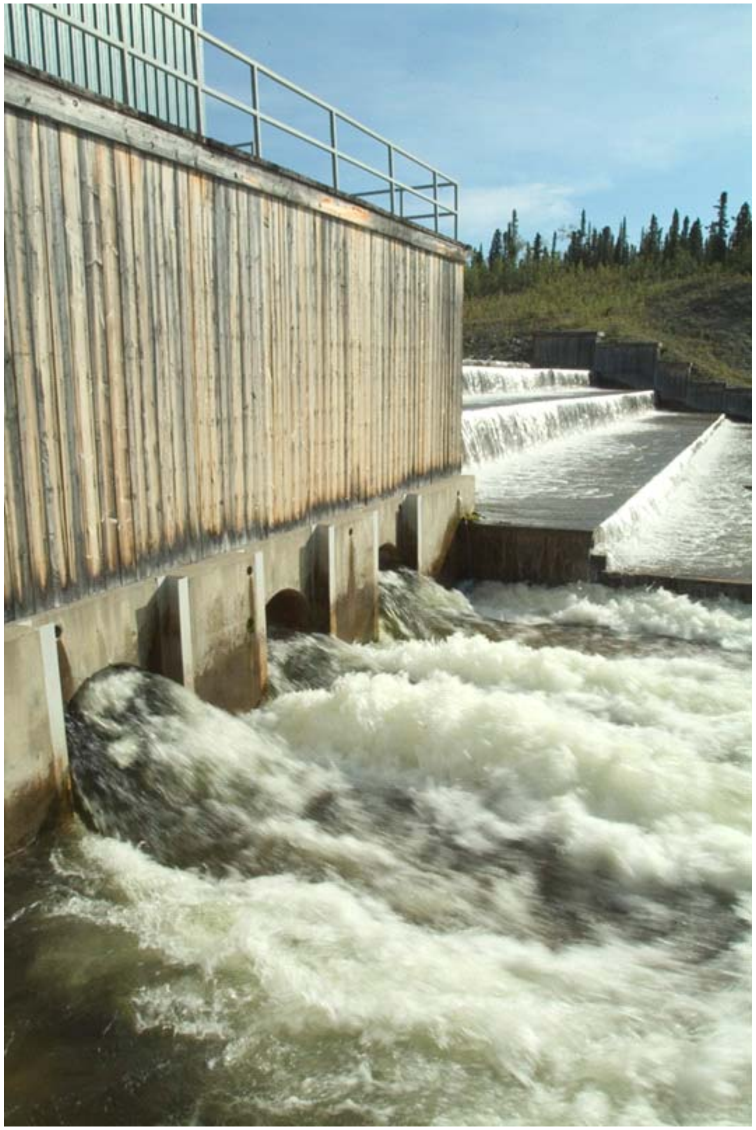
New terms of the 17-year licence provide for a conditional seven-foot operating range subject to the terms of the Department of Fisheries and Oceans ("DFO") Fisheries Act Authorization, and allow for the installation of a third turbine not exceeding 7 MW (subject to the requirement for YTWB approval of an operating plan when the third turbine is installed).

2.2.4 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 by diesel generation,



Mayo Lake Control Structure (www.archbould.com)

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 ("YDC") 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.

The YUB's recent review of the Mayo-Dawson Transmission Line Project has confirmed the project's major ongoing cost savings achieved through displacing diesel fuel generation. These cost savings have been increasing as diesel fuel prices increase. In September 2002, diesel fuel costs were $0.4362/L. In December 2004, fuel prices had jumped to $0.62/L. By late 2005, fuel prices were above $0.80/L.

3.0 SYSTEM CAPABILITY AND CAPACITY PLANNING CRITERIA

This section provides a review of the condition and output of Yukon Energy's assets, and Yukon Energy's new capacity planning criteria.

3.1 SYSTEM CONDITION ASSESSMENT

Yukon Energy has had BC Hydro and Acres Engineering conduct a major assessment of the condition of its key assets. The Condition Assessment findings indicate that other than three diesel units, each of Yukon Energy's generation, transmission and substation assets is well suited to helping meet the future WAF and MD system load requirements over the duration of the Resource Plan.

The condition assessments noted that the three Whitehorse Mirrlees diesel units, WD1, WD2, and WD3, located at the Whitehorse diesel plant are at "end-of life" (see sidebar).

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 today. 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.

A major focus of the current Resource Plan is on addressing the capacity requirements of WAF arising from the planned Mirrlees retirements.

Mirrlees Diesel Units

Three Mirrlees diesel units at Whitehorse with a combined capacity rating of 11.4 MW are currently scheduled for retirement (the nameplate ratings are 14 MW).

- **WD1** currently rated 3.0 MW, installed 1968; retirement 2011;
- **WD2** currently rated 4.2 MW, installed 1968; retirement 2009;
- **WD3** currently rated 4.2 MW, installed 1970; retirement 2007.

The three Mirrlees engines have been planned for retirement for many years, including as far back as the 1992 Resource Plan (assumed to be retired by about 1998-2000). 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 keeping their running hours low 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, based on continued minimal operation.

Further delay in retiring these units is not possible without major investment in "tear-down" overhauls. This is confirmed by BC Hydro's Condition Assessment which found they were at end-of-life. The Mirrlees are also low-speed base load units (514 rpm) which are not well suited to the current WAF stop-and-start operation. In addition, Yukon Energy has concerns with the ongoing ability of the current owner of Mirrlees to provide parts and technical support.

Since January 2006, Yukon Energy has been assessing the possibility of a major life extension project on the Mirrlees units (see Section 4). If these units cannot be refurbished, all three units will need to be retired by 2011.

3.2 CAPACITY PLANNING REVIEW

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.

3.2.1 Background – Capacity Planning Evolution

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.

Utility planning requires that each system have adequate installed generation to supply the required peak capacity (MW) and energy (kW.h) over the course of a year. In Yukon, the primary consideration is peak system capacity, as all systems are fully capable of supplying well in excess of the energy required by customers.

The criteria used by the Northern Canada Power Commission (NCPC) to determine the amount of system capacity required to be in place prior to 1987 were developed to cover relatively small isolated systems, and were consistent with utility planning standards of that era. The criteria considered the ability of a system to supply its load in the event of a generator failure and did not assess the actual likelihood or probability of the failure.

Yukon Energy 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 criteria for isolated systems required the generating capacity with the largest single unit out of service to be 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 (for WAF, a single 15 MW "wheel" at Aishihik), but also probabilities associated with other generators being out of service at the same time (focused on the major WAF diesel units). Consequently, the Resource Plan in 1992 changed the capacity planning criteria to add a new reserve requirement equal to "10% of installed diesel" on top of the 15 MW reserve.

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

Previous Planning Criteria: Under the previous (1992) planning criteria for WAF, the result is that a peak WAF load of 68.7 MW would be allowed in 2006 under these criteria without exceeding the calculated capability of the current generating units in service.

Current WAF Generation 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

In contrast to the 1992 Yukon capacity planning criteria, integrated utilities today typically use a probability-based approach to evaluate the maximum loads that a given system can safely carry by identifying the potential interruption of service for any customer.

An example is the Loss of Load Expectation ("LOLE") measure that forecasts the average number of hours of system outages per year.

Most Canadian utilities apply an LOLE range from one to two hours per year as their capacity planning criteria standard. Some utilities have also 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, the Northwest Territories Power Corporation (NWT Power Corporation) has recently 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 the most severe single system component failure for the Snare-Yellowknife grid.

In summary, capacity planning at other utilities has evolved gradually into more defined ratios as systems have grown larger and more complicated. Reflecting these considerations, Yukon Energy recently undertook an extensive review of capacity planning criteria for its Yukon systems.

Review by Reliability Experts

Yukon Energy's review was undertaken in consultation with reliability experts from the University of Saskatchewan (under the direction of Dr. Roy Billinton) who had been involved in the recent capacity planning reviews and development of new capacity planning criteria in Northwest Territories.

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 those criteria.

Dr. Billinton's work indicated that YEC's capacity criteria as reviewed in the 1992 Resource Plan assured a highly adequate amount of generation (based on LOLE) for residential and commercial WAF customers when the Faro mine was last operating (1996/97). Today, however, Dr. Billinton's work indicated that the 1992 criteria would allow maximum peak loads to reach a level well beyond the reasonable capability of the system before the criteria would indicate new generation was required.

The primary reasons for this conclusion are that the WAF system has substantial hydro generation at Aishihik contingent on the Aishihik transmission line being available. The 1992 criteria did not consider the risks inherent in this transmission connection. In addition, in 1996/97, the system had Faro mine loads that could be interrupted in an emergency as a first resort if the loads began to exceed available generation. Today, there are no similar mine loads to be interrupted, and a similar shortfall condition today would have to be met with outages to core residential and commercial customers.

3.2.2 Yukon Energy Capacity Planning Criteria Review

As a result of its 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 customers from having inadequate amounts of generation available.

Yukon Energy has also recognized that the LOLE function is an average that does not indicate how long any particular outage will last, or the potential severity of consequences for customers. Any extended outage on the WAF or Mayo Dawson grid during the winter peak could be extremely serious for affected residential and commercial customers.

In order to address the severity of a potential outage, Yukon Energy has incorporated a second test as part of its capacity planning criteria, known as the "N-1" standard. This standard ensures there is sufficient generation installed to meet firm residential and commercial customer loads when a failure occurs to the single largest system component. In the case of WAF, this single most critical system component is currently the Aishihik transmission line.

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. Subsequent to preparing this Resource Plan, Yukon Energy on January 29, 2006 experienced a power outage on the WAF grid due to a failure on the connection to the Aishihik generation.

3.3 NEW CAPACITY CRITERIA ADOPTED BY YUKON ENERGY

The following new capacity planning criteria have been adopted by Yukon Energy as a result of its recent review:

__WAF and MD Systems__

1. **WAF and MD system-wide capacity planning criteria:** Each integrated 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 integrated 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.

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.

Benefits of Two-Part Capacity Planning Criteria:

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

- **Probabilistic Criteria:** 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.

- **Emergency Criteria:** Emergency criteria were 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 (the N-1 test).

For isolated diesel communities no change has been made to 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).

The N-1 criterion will not be extended to major industrial customer loads which 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).

Implications of the Adopted Criteria for WAF: 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).

Any further wholesale or retail growth on WAF, as well as all future WAF system diesel unit retirements, will be required to be met with new generation (see table below).

WAF System – Comparison of Capacity Criteria (in MW)

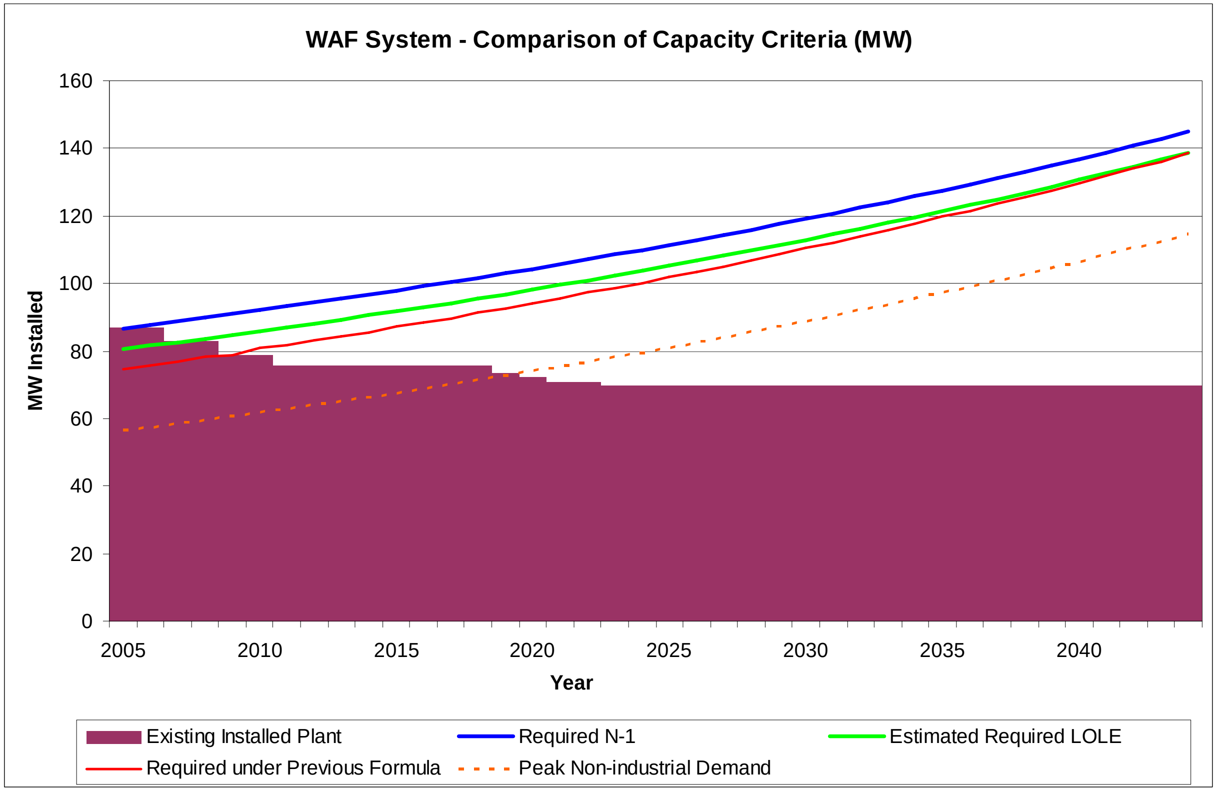
		Previous Criteria			LOLE Criteria			N- 1 Criteria		
Year	**Retirements**	**Peak (WAF wide, including loads served by Fish Lake)**	**Load Carrying Capability**	***Surplus/ (shortfall)***	**Peak (WAF wide, including loads served by Fish Lake)**	**Load Carrying Capability 2 hours/ year LOLE**	***Surplus/ (shortfall)***	**Peak excluding Haines Junction (assumed to be 1 MW)**	**N – 1 criteria load carrying capability**	***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)*

WAF Forecasts: New capacity requirements of 18.7 MW are forecast for WAF by 2012 based on the adopted N-1 criterion as compared with only 12.5 MW based on the adopted LOLE criterion. Consequently the N-1 criterion has governed near term assessment today of new WAF capacity requirements, absent major new mine loads. 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, absent major new mine loads.

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.

Even under the previous capacity planning criteria, the planned retirement of the Mirrlees diesel units combined with expected load growth over the next five to six years would require at least some new capacity to be installed on the WAF system.

Implications for MD: At this time it is clear that MD is well below two hours per year LOLE and satisfies an N-1 condition in all locations. Absent major new mine loads, no new MD capacity is likely to be required for many years into the future.



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.

There are two areas where major investment in the power systems will be required in the next few years: enhancement opportunities for existing facilities, and required investment to address WAF capacity shortfalls.

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.

Enhancement Opportunities: Opportunities currently exist to enhance existing system assets, service new potential loads and make use of possible government infrastructure funding. These include three major project possibilities:

- Aishihik 3rd turbine project
- Revisions to the Marsh Lake water licence to enhance output at the Whitehorse hydro plant
- Carmacks to Stewart Crossing Transmission Project.

The Aishihik 3rd turbine project and the Marsh Lake Fall/Winter storage licence revision are similar to initiatives at other utilities (such as BC Hydro’s enhancement opportunities “Resource Smart” program or Supply Side Enhancement programs at Manitoba Hydro) which focus on providing additional energy or capacity “through physical or operational modifications to existing facilities”.

The extension of WAF transmission north of Carmacks relates to an opportunity to serve two possible new mines in the Carmacks to Pelly Crossing region using available surplus WAF hydro generation, and the potential use of government infrastructure funding for a Carmacks to Stewart Crossing connection of the WAF and MD grids.

Capacity Shortfalls: Investment is required to address WAF system capacity shortfalls, which are forecast to be between 15 and 27 MW within the next six years as load grows and the Mirrlees diesel units are retired. These capacity shortfalls 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.

No near term capacity shortfall requirements are currently expected on the MD system.

4.1 WAF LOAD FORECAST CASES

Yukon Energy’s long-term WAF 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, a review of load forecasting variables used by other Canadian utilities.

YEC has defined sensitivity forecast ranges for non-industrial loads as low, base case (or medium) and high. These are laid out below:

Near Term Non-Industrial 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

The near term WAF requirements are also assessed under variations that include industrial loads of up to about 10 MW. Four specific WAF near term load cases are considered in the Resource Plan:

Base Case: Based on the above forecast ranges, Yukon Energy has developed 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. No new industrial loads are assumed in the Base Case.

Low Sensitivity Case: Yukon Energy has also evaluated resource planning needs under the Low Sensitivity Case. This case maintains non-industrial loads at the low sensitivity level (0.9% growth) and assumes no new industrial loads.

Base Case including Mines: Given the possibility of mines opening in Yukon, a near term case that adds modest mine loads to the Base Case was assessed. This case combines the Base Case assumption for non-industrial (1.85% growth) plus near term development of the Minto (2007-2018) and Carmacks Copper (2008-2016) loads at a combined 9 MW as forecast in late 2005 (minor adjustments have not been made for more recent mine load information filed in the May 2006 Supplemental Materials). This case assumes new transmission to connect these mines with WAF at Carmacks.

High Sensitivity Case, including Mines: In order to prepare for the potential for higher growth, Yukon Energy has also evaluated a high sensitivity case that includes mines. As the highest 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 NEAR TERM REQUIREMENTS

Forecast WAF requirements for new facilities have been assessed for each near term load case, taking into consideration forecast diesel plant retirements.

While there is sufficient energy available in the near term, there is not sufficient capacity to meet the near term WAF winter peak requirements under any of the load forecast cases. The table below illustrates the near term WAF capacity requirements (shortfalls) in the years 2006, 2009, and 2012 under each load case.

Summary of Near Term WAF Capacity Requirements

	Shortfall (MW)		
Load Case	**2006**	**2009**	**2012**
Base Case	0.7	12.3	18.7
Low Sensitivity Case	0.2	10.1	14.7
Base Case With Mine Loads	0.7	15.1	21.5
High Sensitivity Case Including Mines	1.4	17.9	26.7

Under all four load cases, there is a need for additional WAF capacity (MW) beginning in 2006, and increasing to at least 10 MW by 2009. Base Case WAF capacity shortfalls are forecast at 18.7 MW by 2012. Even under the Low Sensitivity Case, the near term WAF capacity shortfall is 14.7 MW in 2012. If two potential new mine loads are considered, the forecast WAF capacity shortfall in 2012 is between 21.5 MW and 26.7 MW.

In contrast, forecast WAF energy requirements (GW.h) can be supplied from existing facilities for the next 20 years under each of the four load cases.

The key WAF energy planning issues are forecasting when growth in firm loads will fully absorb the current WAF surplus hydro generation, and the extent to which costly diesel generation will then be needed to supply baseload energy needs throughout most of each year.

Base Case energy loads indicate no opportunity to develop major new non-diesel generation to displace any material diesel fuel generation requirements until near the end of the 20-year planning horizon. Peaking diesel generation needs, for brief periods during annual WAF peak load periods, will remain less than 10 GW.h/year with the Base Case until after the year 2020. Secondary energy sales on WAF under the Base Case would start to be cut back significantly around 2017, with no surplus hydro remaining for such sales after about 2023. Overall forecast WAF diesel generation by 2025 under the Base Case would approximate 28 GW.h/year.

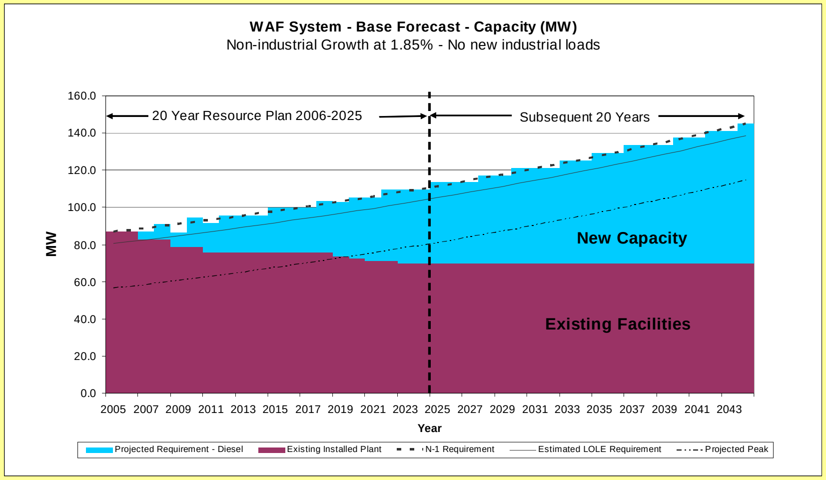
Under the Low Sensitivity Case energy assessment there would be sufficient WAF surplus hydro generation to retain full Secondary energy sales beyond 2025, and surplus hydro energy generation would not be fully utilized until after 2040.

In contrast, Secondary energy sales would be fully curtailed from 2008/09 until after 2016 if the two potential mine loads at Minto and Carmacks Copper are developed in 2007/2008. These mine loads, however, are currently assumed to have a relatively short life with the result that surplus hydro energy generation would re-emerge after about 2016 under the Base Case With Mine Loads.

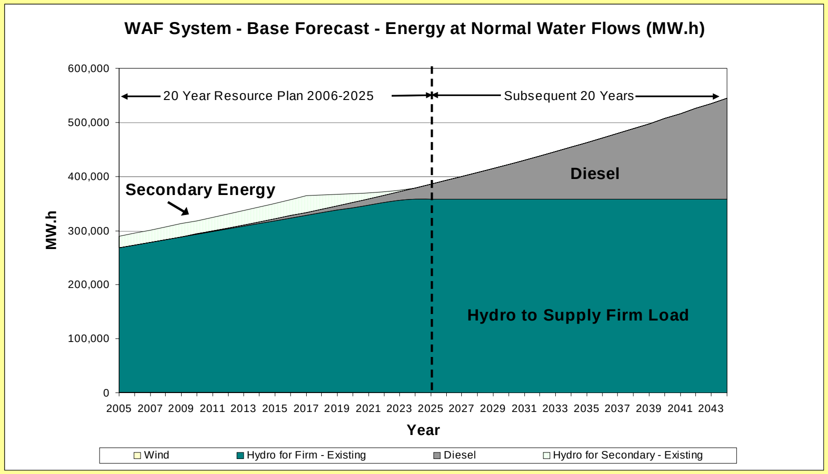
Under the High Sensitivity Case even without any new mines, the WAF surplus hydro energy generation would be fully absorbed by firm loads by about 2017, with diesel generation approximating 50 GW.h per year by 2019 and 124 GW.h per year by 2025. Accordingly, under the High Sensitivity Case Including Mines, there would be no material forecast WAF Secondary energy sales after 2007/2008.

The figures represent Base Case requirements for both capacity (left) and energy (right) over the next 40 years, with the 20 year duration of the current Resource Plan noted by the vertical dotted line. The figures demonstrate that there is no opportunity under the Base Case near term forecast to develop major new non-diesel generation to displace any material diesel fuel generation until near the end of the 20 year planning horizon.

WAF Base Case Capacity Requirements



WAF Base Case Energy Requirements



Existing Capacity is shown in purple, indicating the retirement of the Mirrlees diesels in 2007, 2009 and 2011, as well as later retirement of other small WAF diesels.

New Capacity Requirements with the Base Case are indicated in blue, starting in 2006. The capacity required under the two planning criteria are shown (LOLE and N-1, indicated by solid and dotted lines respectively). New capacity is indicated by assumed generic 4 MW diesel generation units. There is a 0.7 MW capacity shortfall forecast for 2006, increasing to 18.7 MW by 2012 assuming that all three existing Mirrlees units (11.4 MW) have been retired by that time.

The need for additional near term capacity by 2012 remains under the Low Sensitivity Case (14.7 MW), and becomes more pronounced under the Base Case Including Mines (21.5 MW) and High Sensitivity Case Including Mines (26.7 MW) scenarios. The LOLE criteria drive capacity requirements when mine loads exceed about 6.2 MW.

Energy from Existing Hydro Used to Supply Firm Load is shown in green. The long-term average generation capability of WAF hydro is 358,000 MW.h.

Energy from Wind is shown in yellow, but is barely evident during the period to 2019 when the last of the existing wind turbines is planned to be retired.

Energy from Diesel is indicated in grey. During the next 20 years under Base Case loads there is little need for energy from diesel generation except for brief winter peaks. Peaking diesel requirements remain below 10 GW.h per year until after 2020, increasing to about 28 GW.h/year in 2025.

Hydro to Supply Secondary Energy is shown in the uppermost light green section, to a maximum of about 30 GW.h per year. Around 2017 Secondary Energy sales start to be curtailed as firm loads grow to fully utilize the hydro system, and after about 2023 there is no surplus hydro to serve secondary loads under the Base Case.

4.3 PROPOSED NEAR TERM ACTIONS

Four separate major projects are proposed for near term Yukon Energy generation and transmission commitments before 2009. Three of these projects are anticipated to cost $3 million or more.

These proposed major projects are expected to address all near term requirements and opportunities to 2012 and together will provide over 21 MW of new WAF firm winter capacity. This is enough new firm capacity to meet WAF capacity shortfalls of 18.7 MW under the Base forecast, as well as 21.5 MW under the Base Case forecasts plus the Minto and Carmacks Copper mine loads.

Summary of Near Term Proposed Major Projects

Project	Firm WAF capacity (MW)	Other Benefits	Capital Cost (2005$)
Aishihik 3rd Turbine (2009)	0.6 MW (with two mines); otherwise 0 MW	7MW hydro peaking; 5.4 GW.h/yr long-term hydro energy	7 million
Marsh Lake Fall-Winter Storage (2007)	1.6 MW	7.7 GW.h/yr long-term hydro energy	up to 1 million
Carmacks-Stewart Transmission Project (2008/2009)	5.6 MW in 2012; declining as MD load grows	up tp 7.7 GW.h/yr long-term hydro energy; declining as MD load grows	32 million (before YTG & mine contributions)
Mirrlees Life Extension (2007-2009)	14 MW		up to 6.4 million

The four major proposed projects are reviewed below, along with contingency provisions and other proposed actions before 2012.

4.3.1 Aishihik 3rd Turbine Project

The Aishihik 3rd Turbine Project is an enhancement opportunity which was initially reviewed in the 1992 YUB Resource Plan hearing. It will provide 7 MW of added peaking capability 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 $7 million (2005$). Yukon Territorial Water Board and environmental approvals for the project were received in the new Aishihik Water Licence.

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. In the first years of the project, however, adverse rate impacts will occur (from 0.3% with mines to almost 2% with only Base Case loads, assuming 2009 in service). Diminishing rate impacts remain 2-8 years thereafter, depending on the load case, e.g. positive rate impacts will begin in 2011 or 2012 with the Base Case including Mines and project in service in 2009.

Yukon Energy proposes to proceed with final planning of the Aishihik 3rd turbine to enable a final decision during 2007 to start construction for in-service by October 2009. However, if Marsh Lake Fall/Winter Storage is developed (see below) without any additional non-industrial load growth or new industrial loads emerging, the

YUKON ENERGY

final decision to start construction is proposed to be deferred until late 2009 to be in service in 2011 or 2012.

4.3.2 Marsh Lake Fall / Winter Storage Licence Revision:

The Marsh Lake Fall/Winter Storage Project is an enhancement opportunity. This project, which was not reviewed in the 1992 YUB 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. The project will increase annual rate costs by at most 0.28%, offset by the savings in peaking diesel use (which exceed the cost impact by 2013).

Yukon Energy proposes to pursue the amendment to the Whitehorse Rapids water licence, including consultation and environmental licensing by August 2007 (although it is possible that the new Yukon environmental licencing requirements may delay completion of the licence amendment to 2008). The licence amendment seeks 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.

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).

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 vary depending on water conditions (see below).

Marsh Lake Fall / Winter Storage Project - Effects of proposed licence change on Marsh Lake Water Levels:

1. **Normal Water Condition Effects**: 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).

2. **Flood Year Effects**: 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.

3. **Drought Year Effects**: 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.

Maintenance work on one of Yukon Energy's Whitehorse Turbines (www.archbould.com)

4.3.3 Carmacks-Stewart Transmission Project

The Carmacks Stewart Transmission Project is an enhancement opportunity which 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. Assuming no new MD mine loads, it will provide 5.6 MW of additional firm near term capacity and 15 GW.h/year of additional near term energy for WAF.

Development of this project, which is estimated to cost $32 million (2005$), 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. New mine connections to this project will also be required to be funded by customer contributions. Accordingly, if developed, the project will be funded by no-cost capital (e.g., Yukon government funding plus mine customer contributions) to a level that ensures no adverse rate impacts. New mine firm energy use could have beneficial near term rate impacts for Yukon ratepayers.

Planning activities are proceeding with the Carmacks-Stewart project to enable a decision to proceed with construction early in 2007 for an in-service date in approximately mid to late 2008 for at least a first phase from Carmacks to Pelly Crossing (which could supply both the Minto and Carmacks Copper mines, if they are operating, as well as Pelly Crossing). Completion of the second phase to Stewart Crossing to connect the MD and WAF grids may then occur by mid to late 2009.

Line Maintenance (www.archbould.com)

4.3.4 Mirrlees Life Extension Project

The Mirrlees Life Extension Project addresses near term WAF capacity shortfalls through a major refurbishment (Life Extension) of the existing Mirrlees units to gain an extra 20 or more years of service. The Mirrlees Life Extension project will provide an additional 14 MW of firm WAF capacity, sufficient (with the other proposed projects) to meet the remaining near term capacity shortfall under all cases other than the High Sensitivity Case Including Mines.

Assuming development of the Aishihik third turbine and the Marsh Lake Fall/Winter Storage (plus the Carmacks-Stewart Transmission, if Yukon government funding is provided), Yukon Energy will face a WAF capacity shortfall primarily related to the N-1 capacity criterion and the weaknesses associated with the Aishihik transmission line. This shortfall in 2012 varies, depending on the load case assumed, from 7.5 MW (Low Sensitivity Case) to 18.9 MW (High Sensitivity Case Including Mines).

The Mirrlees Life Extension Project is expected to be substantially lower in cost than any other option to secure the needed additional near term capacity. Under Base Case loads, new firm capacity-related average annual rate increase impacts in 2012 would approximate 2.7% (based on net capacity needed from Mirrlees refurbishment plus new diesels, assuming Marsh Lake Fall/Winter Storage in place, no firm capacity contribution from Aishihik 3rd Turbine, and no Carmacks-Stewart Transmission development, i.e., any firm capacity supplied by Carmacks-Stewart transmission is assumed to be assigned costs based on the least cost diesel alternative).

Since January 2006, Yukon Energy has conducted a detailed review of the technical feasibility of the Mirrlees Life Extension as well as further assessments of the Whitehorse Rapids Diesel Plant "common" systems. This review addressed uncertainty as to whether the Mirrlees units can be successfully refurbished and serious concerns as to Yukon Energy's ability to get technical support and parts from the manufacturer for 20 more years. Based on this review, Yukon Energy has determined that a careful and staged Mirrlees Life Extension should be pursued rather than replacing the Mirrlees with new units. In addition, measures to upgrade the Whitehorse Rapids Diesel Plant will also be undertaken.

The Mirrlees Life Extension Project will complete final planning activities in 2006 in order to put the three units in service during 2007 through 2009 at an expected cost of $6.4 million. The specific work will require major tear-downs on the three Mirrlees units plus additional work to update the overall diesel plant systems (such as cooling and fuel delivery systems).

In order to secure in-service by October 2007, planning and commitments for construction/implementation will begin by the summer of 2006 to order parts and carry out other plans for the first Mirrlees unit (5 MW), including repair of the cut winding on the generator plus the plant systems updating.

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.

4.3.5 Contingency: Whitehorse Diesel Replacement and Expansion Project

A contingency plan was assessed to address the near term WAF capacity shortfalls in the event that the Mirrlees Life Extension was determined by Yukon Energy not to be technically feasible.

A new Whitehorse Diesel Replacement and Expansion Project remains as a near term option to replace the three Mirrlees, as they are retired, with new larger diesel units of about 8 MW each. The only other major near term option of the necessary scale would be to develop an Aishihik 2nd Transmission Line to assure Aishihik generation remains available to the rest of the WAF system. Overall, proceeding with the Diesel Replacement/Expansion option appears to be clearly preferred over the Aishihik Twinning option to address near term capacity needs.

Aishihik Twinning Option:

An Aishihik 2nd Transmission Line could be developed to provide 22 MW of firm WAF capacity under the N-1 criterion, or about 14.4 MW under the LOLE criteria. Preliminary estimates indicate a capital cost between $16 and $19 million for this option, with a possible in-service date of 2009 (at the earliest).

Compared with the Diesel Replacement/Expansion option, Yukon Energy has determined that twinning the Aishihik transmission line entails higher costs, a longer planning period, and more risks to project schedule and costs. The line would deliver a material increase in system load carrying capability (up to 22 MW depending on the system load conditions) but does not appear to compete on costs with the diesel-related options. The Aishihik-related option also takes longer to put in place, and exposes the WAF grid to near term and growing capacity shortfalls until it is completed (at the earliest by about 2009).

Yukon Energy will review the Aishihik 2nd Transmission option if new mine loads are connected to WAF without completion of the Carmacks to Stewart Transmission concurrent with a finding that the Mirrlees Life Extension is not technically feasible.

The Diesel Replacement/Expansion option will entail replacing each of the Mirrlees units with a new 8 MW unit as needed (for a maximum 24 MW at the existing site). The cost (2005$) is expected to approximate $0.9 million per MW. Under Base Case loads, new firm capacity-related average annual rate increase impacts in 2012 would approximate 4.6% (using the same assumptions as for Mirrlees project rate assessment).

Under Base Case loads, the first diesel unit (8 MW) would need to be installed by October 2007, requiring 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. The costs in 2007 would include the unit (a capital cost (2005$) of about $7 million (8 MW)) plus updating any common diesel plant systems (about $1.6 million).

Once the first unit is committed under the Diesel Expansion/Replacement option, it is expected that up to two additional diesel units (depending on the unit size selected) would be implemented thereafter as required for in-service before 2012.

4.3.6 Ongoing Monitoring

In addition to the major projects proposed for near term development, Yukon Energy will monitor ongoing annual customer class load trends on each grid (peak capacity and seasonal energy) to facilitate planning and monitoring of the need for major new generation and transmission. Specific new industrial development opportunities for grid power service will continue to receive close attention, including assessment of any mine site power contribution to the supply of reliable grid peak capacity.

4.3.7 Other Small Enhancement Projects

Continued routine utility investment is also proposed to assess and proceed with projects to enhance existing facilities at a cost less than $3 million. This includes:

1. 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)

2. Continued pursuit of opportunities to cost-effectively rewind or re-runner existing hydro generating units at Whitehorse and Aishihik

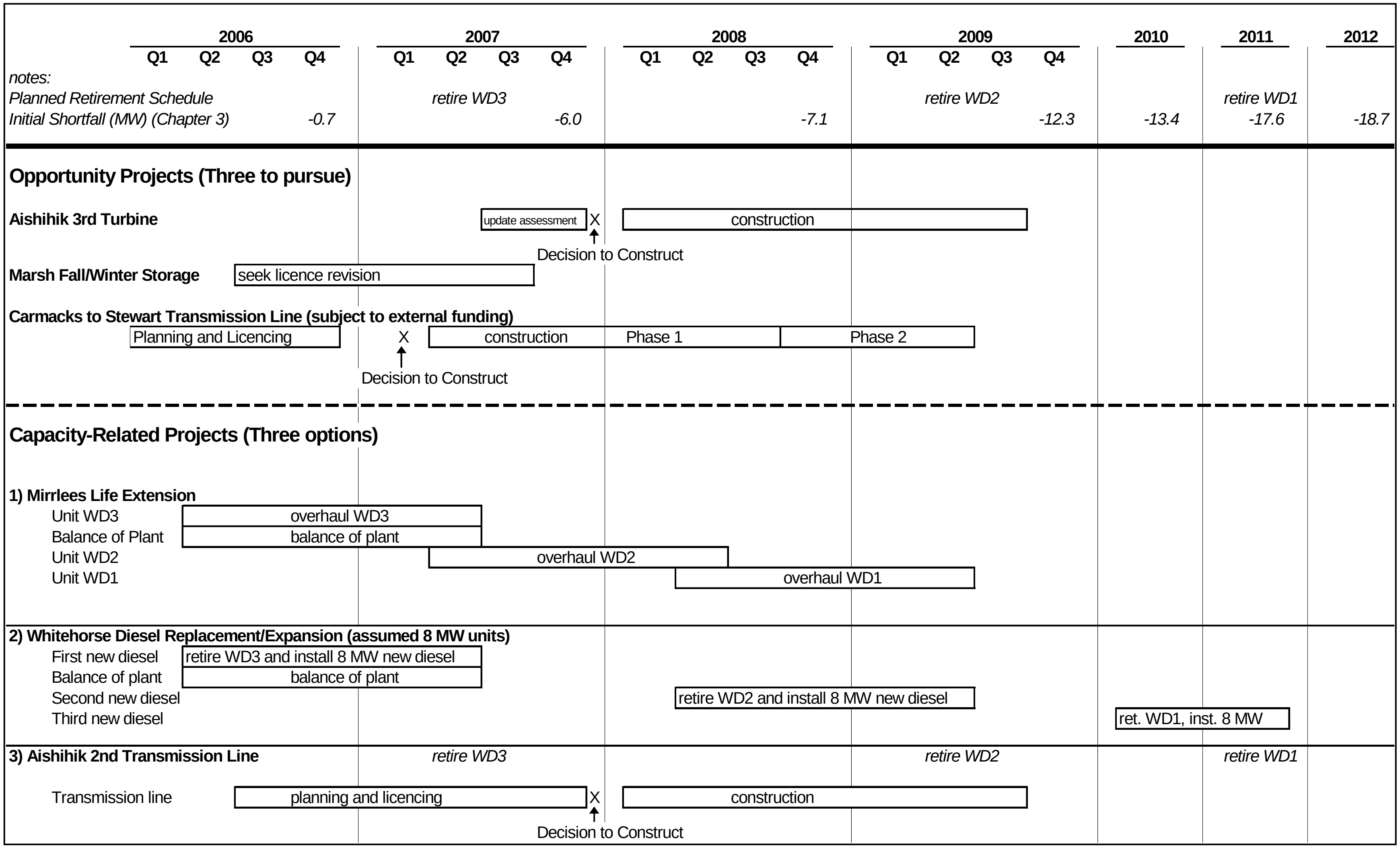
3. Assessing need and timing for a potential 1 MW diesel unit installation at Carcross/Tagish (likely by YECL).

4.3.8 Schedule and Sequencing

As summarized in the attached figure, the proposed near term opportunity and capacity-related projects are generally required to address time sensitive requirements for new capacity, new mines, or Yukon government infrastructure funds.

The Aishihik 3rd Turbine Project is the exception in that it has some flexibility regarding scheduling and in-service date (as it does not contribute in any material way to meeting WAF firm capacity shortfalls).

Timing and Sequencing of Opportunity and Capacity-Related Projects



5.0 INDUSTRIAL DEVELOPMENT OPPORTUNITIES

The Resource Plan sets out proposed planning activities to enable construction of additional generation and transmission projects to start before 2016 in a timely way if opportunities arise to meet the needs of potential new industrial customers. This section summarizes Yukon Energy's proposals beyond the near term (2009), incorporating the near term proposed actions set out in section 4.

Planning preparation is required in light of the significant current interest in Yukon among mining companies, as well as the potential for an Alaska Highway pipeline within the planning period.

The current power system in Yukon is dominated by hydro generation and transmission developed primarily in response to past industrial customers. Sustained opportunities to displace costly diesel generation energy use related to earlier mines provided the basis for these previous bulk electrical supply developments. Although all of the mines that allowed for development of hydro in Yukon are now closed, the hydro infrastructure continues to provide sustained lower cost energy to local residential and commercial power users.

Without new industrial power loads, surplus hydro energy generation is likely to remain on WAF for at least 15 of the next 20 years, removing any basis today to consider new energy-focused development. However, new industrial loads with appropriate scale, location and sustained life that emerge within the next 10 years could change this situation dramatically.

This section examines the power supply planning implications and options related to potential opportunities for industrial developments before 2016.

5.1 PLANNING CONSIDERATIONS

Yukon Energy cannot know today which potential industrial loads might arise within any specific planning period. Nevertheless, there is a need for some level of information on a wide range of resource sites (both size and location) in order to be ready to respond when opportunities arise. Due to the high costs of planning, however, it is also not possible to have a full feasibility level of information or solid reliable cost estimates for each of these sites.

A balanced approach is required to ensure that Yukon Energy is sufficiently prepared so as to "protect" feasible options to proceed with power projects quickly once new industrial loads develop, while at the same time not spending more than is prudent today to protect and advance potential power projects by, for example, proceeding to detailed feasibility stages based on mere load speculation or industrial development scenarios that are highly uncertain.

The proposals for grid-based power supply options in the Resource Plan strike a balance between the two factors – the need for information and readiness versus the costs of achieving that level of preparedness. Additional considerations are also noted with regard to both the potential industrial customer and Yukon Energy.

Factors related to the industrial customer: There is typically considerable uncertainty as to timing and prospects to start and complete construction for a major new industrial development. In addition, mines or pipelines may choose to use on-site generation (diesel or natural gas) as that may be simpler and faster and allow them to make use of waste heat from the units. On-site generation can also be cheaper than grid hydro power if the load is only going to last for a short time (such as 5-10 years or less) or is at too great a distance from the grid.

Yukon Energy factors: A key factor for Yukon Energy is that, unlike many southern jurisdictions with export connections, Yukon Energy cannot secure any economic value from surplus hydro since it does not have grid interconnections with external markets (although a relatively small amount of surplus hydro can be sold at secondary rates in Yukon). For this reason, there is considerably more risk to developing capital intensive power projects in Yukon than in, say, Manitoba or British Columbia where failure of local loads to develop as planned can be offset by the opportunity to sell additional power on export markets. 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 (see discussion of Whitehorse Rapids unit #4).

In some industrial development scenarios examined in this Resource Plan, the magnitude of required new generation and transmission may also be at or beyond the current capability of Yukon Energy, or other Yukon entities, to finance and construct 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.

Need for Balance – Readiness Versus Costs

When planning for grid-based power supply to new industrial loads, Yukon Energy must balance two key factors:

Readiness and Timing in relation to supplying new loads: If Yukon Energy waits until a mine is a certainty before even beginning the planning processes, it is unlikely the new power can be delivered within any reasonable period of time after the mine opens, and the opportunity may be lost. Once all their approvals and financing are in place, mines can typically be built and put into operation fairly quickly (sometimes 1-2 years or less), particularly if they can rely upon on-site diesel power generation. In contrast, development of a new major non-diesel power resource from initial planning stages to first power can take much longer (easily 3-4 years or much more for a hydro plant).

Costs, timelines and risks for resource project planning: The planning phases for new non-diesel generation or transmission can be costly and require many years of work prior to Yukon Energy being in a position to start on construction. Planning costs can total $1 to $5 million for very small hydro projects (smaller than the existing Mayo plant), up to about $20 million for medium size hydro projects (similar to the existing Aishihik plant) and up to about $40 million for projects in the size range of 40-50 MW. There are also risks that after spending substantial amounts on planning studies, the information will indicate that a resource project is not feasible (or that the industrial load for which it is being planned is not proceeding, or has significantly changed its expected scale, timing or other key factors).

WHITEHORSE RAPIDS UNIT #4

The risks inherent in developing power projects in Yukon are well illustrated by the history of the "fourth wheel" at Whitehorse Rapids. The first three units were brought into service in the 1950's and 1960's basically sized to capture all the river flows in winter. However, during the summer the Yukon River flows were higher, and the three units could not make use of all of the water. To capture this extra energy to displace diesel generation, NCPC constructed Whitehorse unit #4 in the 1980s. This unit basically provides almost exclusively summer energy, and was developed on the expectation that the Faro mine would continue operating.

During construction of unit #4 the Faro mine closed. As a result, at the time of commissioning the unit provided no economic value to the system.

When Yukon bought the assets of NCPC, the Yukon Government negotiated a $40 million flexible term note with the Government of Canada to ensure that Canada retained all market risks related to this unit. When WAF loads were low enough that unit #4 was providing reduced value, the Government of Canada charged reduced interest and principal on the loan.

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.

5.2 REGULATORY AND POLICY FRAMEWORK FOR SERVING INDUSTRIAL CUSTOMERS

There are a number of regulatory and policy factors that need to be considered when planning grid power service to industrial customers. In addition to assessing the economics of new bulk electrical supply projects (including attendant risks), Yukon Energy needs to assess potential rate impacts on other utility customers and on new industrial customers, as well as overall Yukon policy objectives.

Pay full cost of service: Industrial customers connected to the integrated power system in Yukon are required to pay the full costs to serve them, under Yukon Government OIC 1995/90. New customers are also required to pay all costs to connect the existing grid to their site (including any new transmission) such that existing customers are not adversely impacted by the new customer.

Opportunity to sell existing surplus power: With major surplus hydro energy today on WAF and MD grids, new industrial customers within the next decade will provide opportunities for Yukon Energy to sell this power at firm rates with very little incremental cost. This will be a beneficial rate driver for other current customers on all systems in Yukon (as rates are equalized throughout the territory, all Yukoners benefit from sales of surplus hydro, even those in diesel communities).

Must meet normal utility "obligation to serve": If a new industrial customer is located within areas presently served by Yukon Energy grid power, Yukon Energy must take into consideration its 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. Major new industrial customers located far away from the current grids would in all likelihood not be added to the Yukon grid systems due primarily to the costs of transmission connections. Without such connections, new major industrial loads would typically be supplied by isolated on-site diesel generation with all costs excluded from YUB consideration in rate setting.

BROAD POLICY OBJECTIVES FOR NEW POWER DEVELOPMENTS

When considering new power developments, most jurisdictions in Canada are guided by a set of broad policy objectives set by governments, regulators or others. 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.

In Yukon, the traditional energy policy objectives have been focused on development, where economically feasible, of local resources instead of 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 what is needed to supply industrial customers).

In addition, Yukon Energy developed the Mayo-Dawson transmission line to economically displace imported diesel fuel with hydro from Mayo.

The Resource Plan reflects a continuation of this broad policy objective of economically developing local resources to avoid, where possible, the need to generate power with diesel.

If load is sufficiently large and sustained, there is an opportunity to put in place new generation and transmission infrastructure: For sufficiently large long-term new industrial loads, WAF or MD would have to run substantial new diesel generation unless new hydro or other baseload generation can be developed. For this reason, Yukon Energy needs to consider carefully the options and impacts of serving new loads that would be primarily served by added diesel generation. 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.

Overall, looking at longer-term implications, new industrial loads are likely to be attractive economically to the existing grid system only if they allow utilization of existing surplus hydro generation or development of new capital intensive low-cost generation, such as occurred with the original opportunities to develop Mayo or Aishihik.

5.3 THE IMPORTANCE OF MATCHING OPPORTUNITY TO LOAD

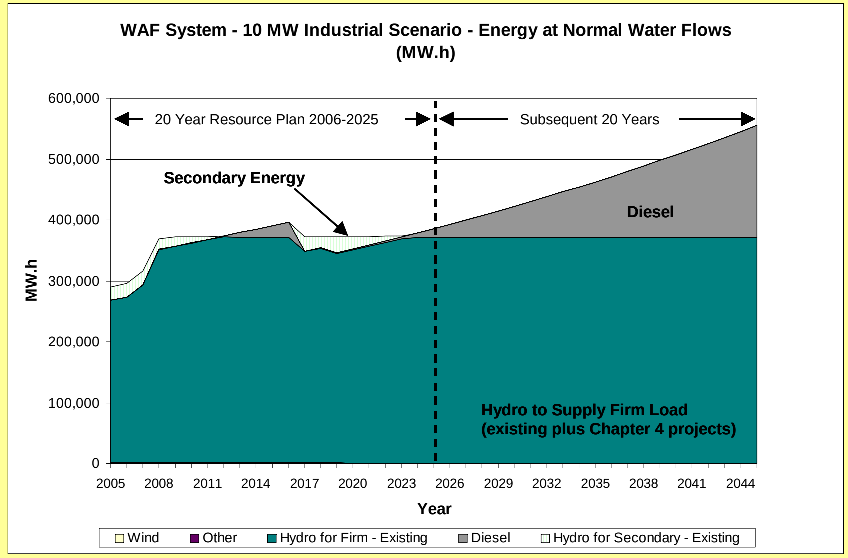
The following three scenarios demonstrate the importance of matching new WAF energy supply opportunities to overall WAF energy loads. Each scenario assumes near term development of Marsh Lake Fall/Winter Top Storage and the Aishihik 3rd Turbine Project as proposed in Section 4.

Yukon Energy's analysis demonstrates that opportunities to add non-diesel generation do not begin to emerge until WAF loads are of a sufficient size and duration to have substantial and ongoing diesel energy requirements that can be displaced by new capital intensive energy supply resource options.

- With the addition of a 10 MW industrial load, it would be difficult to justify even considering new energy projects for commitment before 2016.
- With the addition of a much larger industrial load (e.g., 25 MW or larger), the duration of the new load would be critical to assessing the viability of adding non-diesel generation to the system.

With the addition of a 40 MW industrial load, the opportunity to add non-diesel generation up to the 30 MW range does begin to emerge. However, the duration of the industrial loads remains critical. If the mines were to close by 2035 as assumed in the scenarios, the hydro system with a 30 MW additional unit would be overbuilt to serve the non-industrial loads at that time.

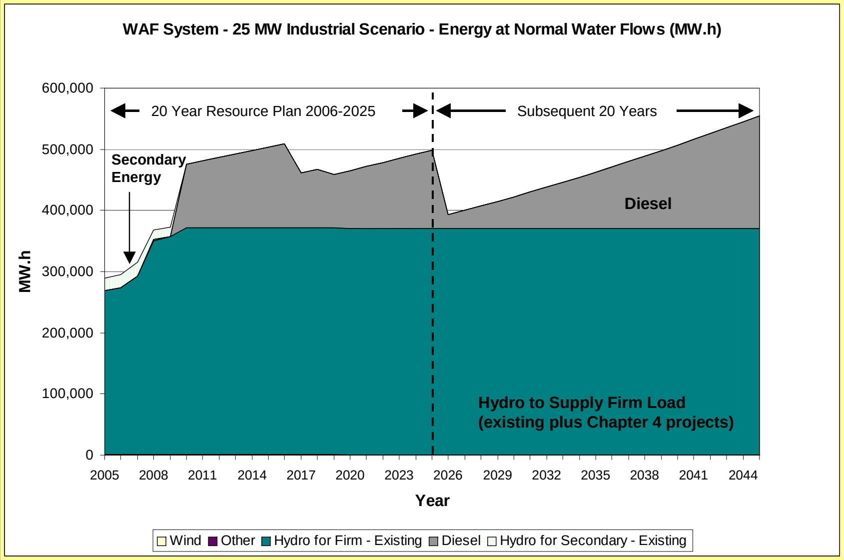
10 MW INDUSTRIAL WAF LOAD SCENARIO



The load balance information above assumes two mines (Minto and Carmacks Copper) starting operation in 2007/08 (Base Case with Mines load in Section 4). Over the next 20 years (the period of the current Resource Plan), the maximum diesel requirement with existing resources 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, average about 2 GW.h/year, and reflect the current hydro generation surplus.

Under this load size, 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.

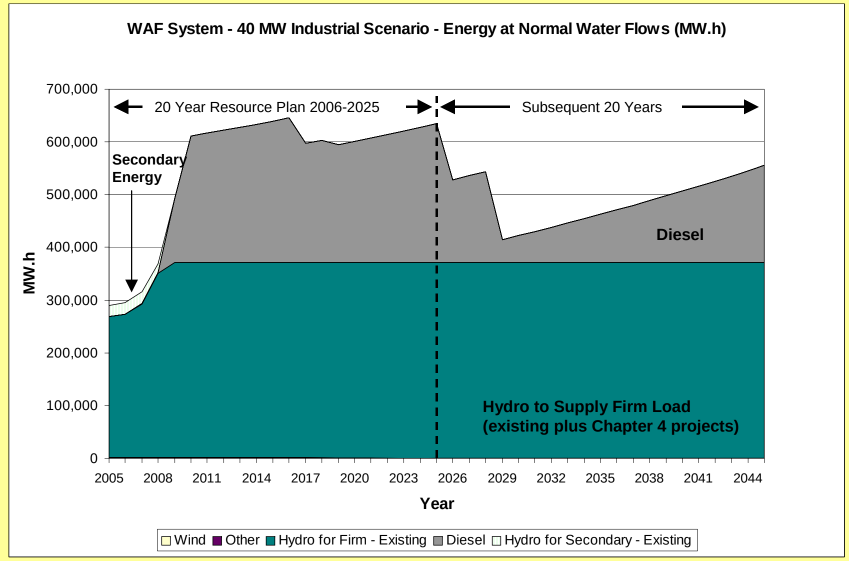
25 MW INDUSTRIAL WAF LOAD SCENARIO



This scenario adds to the 10 MW scenario, in 2010, an assumed 15 MW industrial load with a 15 year life. The assumed load size with existing resources 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 90 to 140 GW.h/year from 2010 to 2025. As the new industrial loads close, however, diesel generation would approximate 21 GW.h/year (growing 7 to 8 GW.h/year as WAF non-industrial load grows) and not reaching the 100 GW.h per year level again until 2036.

40 MW INDUSTRIAL WAF LOAD SCENARIO



The scenario adds to the 25 MW scenario, in 2009, an assumed 20 MW industrial load with a 20 year life. For a period of 16 years, the magnitude of diesel generation under this scenario with existing resources 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 non-diesel development, over the life of the mines diesel generation would supply about 85% of the mine load incremental generation.

After the period of mine closures (assumed at 2029), the WAF system would be back down to a non-industrial load level requiring all the existing hydro output plus 44 GW.h of diesel generation.

5.4 INDENTIFYING AND ASSESSING OPPORTUNITIES

Yukon Energy has examined a range of potential industrial development opportunities that might start operation in Yukon within the next decade (by 2016). The potential opportunities as set out at page 44 display widely varying requirements (from 5 to 13 years or more, peak demands ranging from 2 to 360 MW, and distance to the established Yukon grids from 0 km to 273 km).

The types of power resource developments that might be enabled by these potential industrial opportunities depend entirely on the scale and, equally important, the duration of the loads to be served. At this time, potential developments to serve these loads can be considered only on a "screening" basis, given insufficient information about either the potential loads or the potential resource projects to fully assess project feasibility.

The Resource Plan focuses on major generation resource options that have the potential to supply both energy (kW.h) and capacity (kW) of a scale required to service interconnected grids and industrial loads. These primarily consist of hydro generation. Should major new industrial loads arise, consideration will also need to be given at that time to alternative generation technologies that only supply energy (such as wind, coal, solar, certain forms of DSM) as well as technologies that today are not sufficiently mature but are the subject of either ongoing research and development or further assessment of potential in Yukon (such as geothermal, coal bed methane, various alternative approaches to biomass generation, or small nuclear). A summary of electrical generation technology relevant to Yukon is set out in a "Backgrounder" at the end of this Overview.

For major new generation resource options, at a screening level four key considerations are looked at (aside from environmental or other factors that may preclude certain developments):

1) **Cost of energy generated (LCOE):** One main consideration is the basic generation cost of energy supplied. For the purposes of initial screening, "levelized costs of energy" or LCOE is used where feasible to determine the unit costs/kW.h for generation at the project site. Levelized costs reflect average unit costs of the plant over its full life assessed on real dollar (2005$) economic terms (i.e., assuming the unit cost after 2005 increases with inflation each year, and that all output is fully utilized). A detailed description of the approach to determining the levelized cost of energy is provided in the Resource Plan Submission. Levelized costs allow Yukon Energy to screen potential generation sources to determine those that are clearly uneconomic versus those that require further assessment.

2) **Location and cost of transmission:** If attractive supply options (such as hydro) can be identified that offer materially 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 far from existing transmission may not be able to support the costs 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). If some or all of the power provided is surplus to system load requirements (e.g., becomes spilled hydro or an idle coal plant) even otherwise very low cost resource options can be uneconomic to the overall power system. Key considerations in the Resource Plan 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, there will be extra annual charges on the project that do not occur in Yukon.

Potential Hydro Generation Supply Options

	Grid	Installed MW	Annual Energy (GWh)	Capital Cost (2005$millions) (excl. trans.)	Trans. Distance (km)	In BC	Capital Cost LCOE (cents/KWh) excl. trans (2005$ real)
Existing Hydro Enhancements							
Aishihik Diversions	WAF	0	total of 24	n/a	0		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		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		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		7.2
Very Large Hydro Sites (60+ MW)							
Granite	WAF	80 (up to 250)	660	706	125		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

Yukon Energy has developed an inventory of many potential major generation sources, including 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) as well as potential coal generation. Potential hydro supply options based on past studies (and not subject to any update assessments) are set out in the adjacent table. (See also the map on page 9 for location of hydro and coal options.)

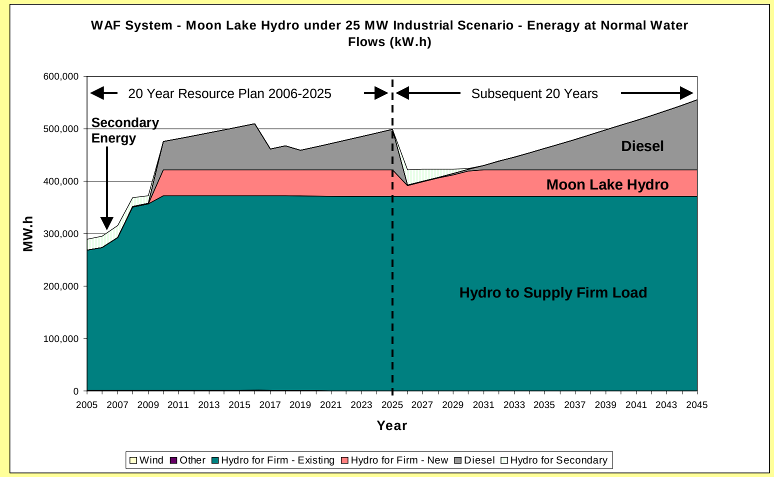
Matching Hydro Opportunities to Load

Hydro plants have service lives of up to 100 years. However, mines typically have service lives of less than 20 years. In order to be considered economic, projects that are developed in response to industrial development often must continue to provide a benefit even after an industrial customer leaves the system. Consequently, it is important to ensure that the system is not overbuilt in the longer term.

- Very small hydro projects in the range of 1-4 MW may be candidates for development under forecasts under a 10 MW industrial scenario or larger (at the very maximum that a 10 MW scenario can handle).
- Small hydro projects in the range of 5-10 MW may be candidates for development under forecasts under a 25 MW industrial scenario or larger. These projects may also be part of a development plan under a larger 40 MW scenario.
- Medium sized hydro projects in the rage of 10-30 MW have potential fit to a 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.

  Large sized hydro projects in the range of 30-60 MW, or very large projects of 60 MW or greater, 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.

WAF Energy Requirements under 25 MW Scenario with Moon Lake Hydro

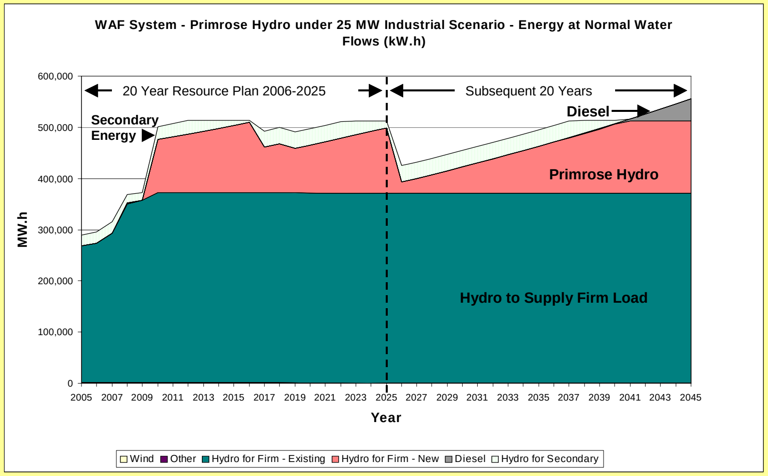


A small project (5-10 MW) such as Moon Lake hydro, would be a good fit for the 25 MW industrial load scenario shown here. The project would continue to provide a benefit, even after the industrial customer left WAF (assumed here after 2025).

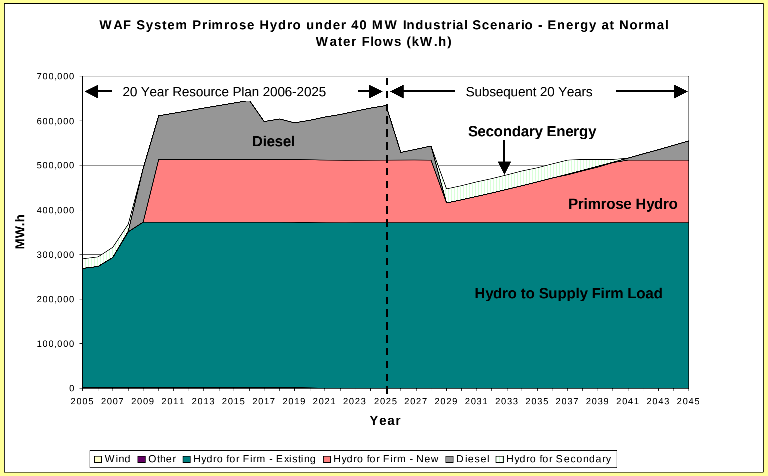
The proposed Moon Lake project would have a capacity of 8.5 MW with 50 GW.h of annual generation at an estimated capital cost of $51 million (2005$).

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 in 2029) as shown above. This surplus could be sold at Secondary Energy rates.

WAF Energy Requirements under 25 MW Scenario with Primrose Hydro



WAF Energy Requirements under 40 MW Scenario with Primrose Hydro



In contrast, a medium project (10 to 30 MW) such as Primrose, (see above) would not fit well with the 25 MW industrial load scenario. The primary Primrose concept reviewed to date is 28 MW, 141 GW.h/year estimated at $191 million (2005$). If developed with this load scenario, the size would be well in excess of the system requirements in many years (a portion of the excess hydro is shown as being sold under Secondary Energy rates).

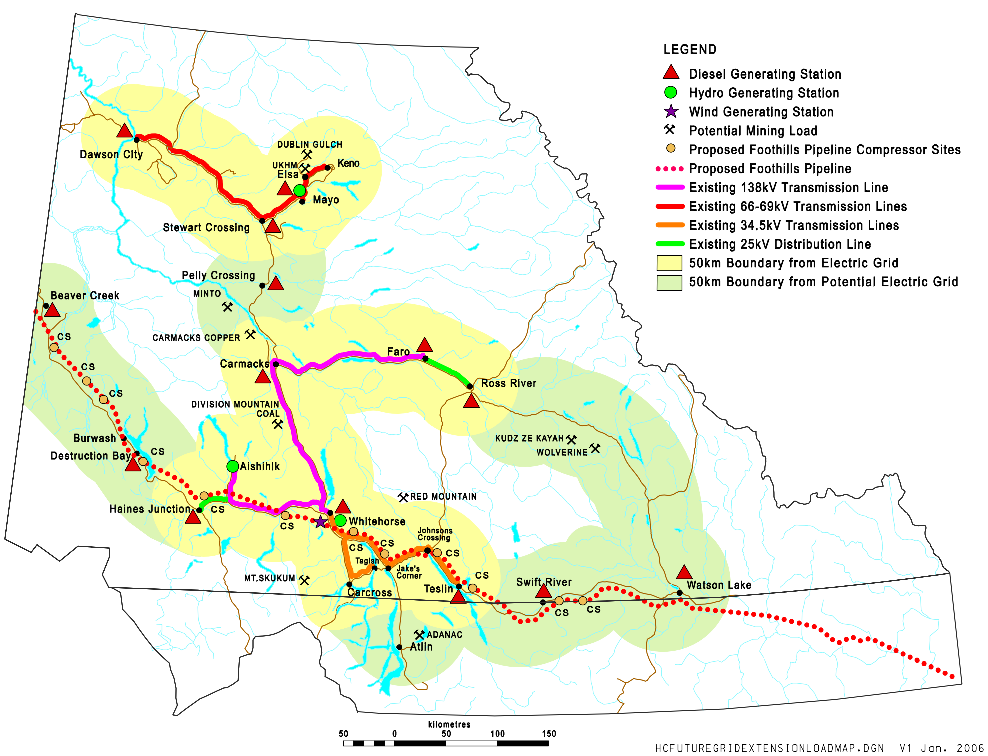
The above 25 MW industrial scenario could fit well with environmentally sound coal generation technology because the service life of a coal plant is approximately 20 years, which may correspond well with the life of a mine of this size.

With a larger 40 MW load scenario a site such as Primrose may be a good fit, but could still face a lack of load after closure of the mines, creating the potential for material surplus energy at that time (there is also the potential for temporary adverse rate impacts). For example, were Primrose to be developed to service the 40 MW Industrial load scenario shown above, its output would be fully utilized from the date of in-service to 2028. Starting in 2029, however, when the mines are assumed to close, the facility would be in excess of WAF needs (about 2/3 of its output would be surplus declining over time). This hydro surplus would extend through 2040. This example underlines the relevance of mine life as well as timing for such developments relative to overall WAF loads.

POTENTIAL INDUSTRIAL DEVELOPMENT OPPORTUNITIES

Load Locations

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL LOADS



Load Details

Project	Proponent	Distance to Grid (km)	Peak Demand (MW)	Annual Energy (GW.h)	Project Life	Possible In-Service Date
Alaska Highway Pipeline, WAF						
120 MW to 360 MW[1]						
Kluane Compressor	Foothills Pipeline	147.2	30	223.4	30	2012-15
Champagne Compressor	Foothills Pipeline	3	30	223.4	30	2012-15
Marsh Lake Compressor	Foothills Pipeline	30	30	223.4	30	2012-15
Rancheria Compressor	Foothills Pipeline	330	30	223.4	30	2012-15
Potential Mine Developments, WAF						
11 to 20 MW						
Division Mountain Coal	Cash Minerals Ltd.	20	5	35	15	2010
Red Mountain	Tintina Mines Ltd.	83	11 to 20	81 to 126	20	2009
Adanac	Adanac	approx. 120	15	Unknown	20	2010
1 to 10 MW						
Minto Property	Sherwood Mining Corp.	98	3	22 to 28	8	2007
Carmacks Property	Western Copper Corp.	53	7.3	48	8.5	2008
Wolverine	Yukon Zinc	273	5.1	37	9	2009
Kudz Ze Kayah	Teck	218	8.8	63	11	2011
Mt. Skukum	Tagish Lake Gold Corp.	47	3	16	8	2008
Potential Mine Developments, MD						
1 to 10 MW						
Dublin Gulch Property	Strata Gold Corp.	27	4	20	10	2009
UKHM	Alexco Resource Corp.	0	2	14	5	2008

[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.

When considering potential start dates and development uncertainties for any of the above mine projects, it is relevant to note that many of these industrial developments have been under active consideration as "near term development" prospects for some time.

5.5 PROPOSED ACTIONS

Yukon Energy proposes planning activities as set out below to address a wide range of potential industrial developments beyond the near term (2009), 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.

Proposed planning activities focus on currently identified energy supply resource options at different scales to reflect the various possible industrial load opportunities that might arise on WAF before 2016.

At a preliminary level, all hydro and coal energy supply resource options examined in the Resource Plan offer substantial opportunities to produce power over the long term at a cost lower than diesel at 20 cents/kW.h in 2005$. Matching energy supply resource options to expected WAF loads, however, is the key planning prerequisite to select feasible energy supply resource options. In particular, the reliable expected life of new industrial loads, rather than only their size, often is critical to the feasibility of developing specific capital intensive energy supply resource options to displace diesel generation.

Due to the high price of diesel fuel today, rate impacts from each of the supply resource options examined are expected to be positive from the outset relative to reliance on diesel generation, assuming effective matching of new supply to reliable firm loads.

5.5.1 Potential WAF Industrial Loads of up to 10 MW before 2016

Potential WAF industrial loads of up to 10 MW before 2016 can largely be served with the projects proposed in section 4. This scale of industrial load does not provide support for commitments of any new hydro site development before 2016 unless mine loads of at least 10 MW are sustained well into the future (well beyond 2016). Even with long-lived 10 MW industrial loads, only the smallest hydro site options (1-4 MW) basically located on the established transmission grid could potentially be supported.

If loads of this scale and duration develop, further consideration will be given to DSM programming focused primarily on reduction of system peak demand. The Resource Plan also sets out various other specific planning activities consistent with this range of WAF industrial loads developing before 2016.

5.5.2 Potential WAF Industrial Loads ranging from 10 to 25 MW before 2016

If industrial loads are committed on WAF before 2016 for development of more than 10 MW (70 GW.h/year) but up to about 20-25 MW (comparable to the Faro mine) for a period through to at least 2025, planning activities should be carried out to allow commitment before 2016 to develop new small hydro site resources within 50 km to at most 100 km of the established transmission grid to provide approximately 50 GW.h per year (7-10 MW) of diesel displacing energy to WAF.

Review of these load opportunities underlines a need to ensure development of new capital intensive energy supply resource options. Without such resource developments, diesel baseload generation could range from 90 to 140 GW.h/year, supplying on average 70% of the mine load incremental generation.

The scale limitations on capital intensive energy supply resource options, however, reflect in part the assumed mine life (i.e., only about 21 GW.h/year of the new generation can be used in 2025 after the assumed mine closing, although this load would be growing at 7 to 8 GW.h/year and thus exceed 50 GW.h/year within four years). In addition, other options more suited to a shorter operating life than hydro generation (e.g., thermal generation options using coal) are not likely to be feasible for energy loads below about 140 GW.h/year over at least 20 years.

In pursuing hydro supply options, new Yukon-based projects, if available, would be the preference due the extra costs of developing a project in BC. However, no recent studies have been conducted to consider potential Yukon-based sites in this size range (few decent sites in this size range were identified in the earlier reviews).

In the event that loads of this scale develop and a coal mine is also developed in Yukon, an environmentally sound coal generation technology should be reviewed to determine the potential for an economic coal development at sizes below 20 MW (140 GW.h/year), sized as appropriate to fit the industrial loads being developed at that time.

The Resource Plan also sets out various other planning activities consistent with this range of WAF industrial loads developing before 2016, including considering DSM and wind activities.

5.5.3 Potential WAF Industrial Loads ranging from 25 to 40 MW before 2016

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, then Yukon Energy proposes to do planning towards project 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.

Under this load forecast, new medium scale hydro projects within reasonable proximity to the established grid would be appropriate for consideration. The development of hydro generation to serve these loads, however, would appear to involve substantial generation capital costs ($180 million or more (2005$)), including significant planning costs (about $20 million) prior to a decision to proceed with construction; material transmission costs would also likely be required. Such costs are likely at or beyond the limits of Yukon Energy's current financial capabilities and involve material risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants be brought on-line.

Coal resource options to supply such loads could involve far less capital than comparable hydro sites, provided that coal supply was otherwise available from developed Yukon sources. The scale of 20 MW (140 GW.h/year), however, is still very small for coal thermal technology and would require careful screening and feasibility assessments to confirm its potential feasibility.

DSM and wind resource development would also be considered under this load scenario.

5.5.4 Potential WAF Industrial Loads with Alaska Highway Pipeline before 2016 (120 to 360 MW)

At this time a pipeline scenario 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, key activities proposed for the near term involve 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 screening large scale hydro site options and related transmission requirements).
- More detailed power supply opportunities focused on compressor "station service" loads.
- Options to use natural gas for power generation to serve other incremental industrial loads cost effectively.

The development of generation and transmission to serve pipeline compression loads (120 MW to possibly as high as 360 MW) 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 be brought on-line. Prior to carrying out planning activities of any specific site or any technology-specific studies, it is proposed that Yukon Energy identify and assess options to deal with this issue, such as joint venturing with others and/or options to secure external government or other financing.

5.5.5 Proposed "Pre-commitment" activities

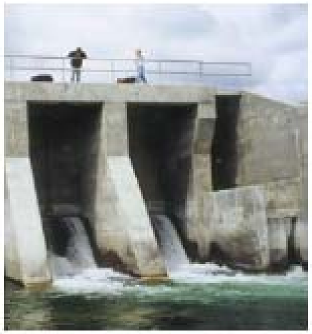
Prior to any certainty developing regarding any specific industrial load scenarios that may arise, it is proposed that Yukon Energy remain focused on planning activities to ensure protection of the options to address the range of potential new loads:

- **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, the Yukon Chamber of Mines and member activities with other 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).

- **Existing hydro facility enhancements:** Continued focus on projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases, Mayo, including assessment and studies of the hydrology of the Southern Lakes area.

- **Preliminary 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 pre-feasibility 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. As a result, no activities are recommended today. However, in the event that at least one large industrial load (such as Red Mountain mine) 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 full 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).




Aishihik Dam (Derek Crowe) and Powerhouse (Yukon Energy)

6.0 NEXT STEPS FOR YUKON ENERGY

Yukon Energy welcomes review and comment by the YUB on the 20-Year Resource Plan. Yukon Energy will also be visiting Yukon communities to inform the public about the content of the Resource Plan, and to receive input from Yukoners.

6.1 SUBMISSION TO THE YUB

On June 1, 2006 Yukon Energy submitted its 2006-2025 Resource Plan to the YUB.

In submitting the Resource Plan, Yukon Energy is also providing for a review by the YUB before going forward with any major near term projects with costs greater than $3 million.

Yukon Energy is also planning broader public consultations to provide information on the Submission, and to obtain feedback from Yukoners.

6.2 ROLE OF PUBLIC INVOLVEMENT

Yukon Energy will be visiting Yukon communities to engage and involve the public in Yukon Energy's Resource Planning process. The purpose of this consultation will be to inform the public about the Resource Plan, and the recommended project options and activities identified by Yukon Energy, and to receive feedback from the public on these recommendations. The dates and locations of the public meetings will be advertised in the local media.

Yukon Energy has not made final decisions to develop any specific near or long term projects, although, as noted in the Resource Plan, ongoing actions are being taken to protect YEC's ability to proceed (particularly with the initial Life Extension Project for the first Mirrlees diesel unit).

During the public involvement process, Yukon Energy will provide Yukoners with updates on its analysis of resource options as set out in the Supplemental Materials included in its June filing with the YUB.

Yukon Energy will integrate the feedback that is received during the public involvement process and any YUB review process into its final planning for both near and long-term requirements.

Aishihik Dam (Derek Crowe)

Backgrounder: The following two pages provide 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: http://www.areca.org/areca/energy_sys.htm) and a more site-specific review "Galena Electric power – A Situational Analysis (pre-publication draft)" (available online: http://www.iser.uaa.alaska.edu/Publications/Galena_power_draftfinal_15Dec2004.pdf).

Diesel: 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 low risk source of supply if loads are uncertain.

Diesel is expensive for utility operations running to provide sustained energy on a regular basis throughout the year.

Hydro: 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 annually 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 if industrial development occurs.

Wind: 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.

Capital costs for wind generation are 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 elevation sites in Yukon). The 660 kW turbine at Haekel Hill had YDC contributions of $2.08 million.

New wind generators continue to come down in price. However, the scale of new wind turbine models is also growing, and is now approaching a range that could not be easily integrated into Yukon systems other than WAF (1.5 MW or more per unit).

Wind is also not a form of reliable capacity for 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.

The feasibility of using wind is very sensitive to wind regime and availability. Utility industry experience indicates that wind economics essentially require an average capacity factor of 30%, while high grade commercial installation requirements 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.

On WAF, future industrial loads that push the system onto material diesel generation may enable commercial development of wind as a complement to other resources. 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.

Coal (thermal generation): 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. While 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 as a resource in Yukon is the development of indigenous coal deposits independent of power generation requirements.

Biomass (thermal generation): Biomass use for thermal generation is subject to the same economic scale constraints as noted for coal thermal generation. In addition, 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.

1. Fuel (typically wood) must be available from a source that would otherwise give rise to disposal costs. Economic biomass generation is not typically possible with a wood product that has a cost to harvest, or even (in some cases) that can be delivered to the plant for free; there have to be savings from avoided disposal costs.
2. 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.

Coal-Bed Methane: 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 to be economic, the site must be close to a population base. In Yukon, no developed resources for coal-bed methane are available.

Natural Gas: 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. However, natural gas could become available during the planning period.

Geothermal: Using heat energy from a geothermal resource is practical only if the geothermal occurrence and the energy requirement 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.

Hydrogen: 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.

Solar: 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. Consequently, 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.

In isolated areas where grid power is not an option, residential and small commercial applications for mining camps and lodges, especially those with greater or solely summertime use, solar power may be considered a viable option.

Nuclear: For Yukon, there is no commercial availability of nuclear generation, and its future commercial availability is unknown. However many characteristics (size, life, efficiency, cost) of a project considered for Galena, Alaska could be very attractive for consideration in Yukon. Other relevant considerations (including security and waste disposal) will clearly need substantial further attention before determining the true potential for nuclear in Yukon.

Demand Side Management: Yukon has been engaged in DSM activities of various types since 1992. 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, water is used to generate electricity or is spilled).

In the near term in Yukon, the electrical system requirements are almost entirely related to peak capacity. Non-industrial DSM programming is generally more successful at energy reductions than capacity reductions. As such, DSM has limited potential to address current utility requirements. 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, 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.

BRITISH COLUMBIA UTILITIES COMMISSION

Resource Planning Guidelines

Issued: December 2003

TABLE OF CONTENTS

PURPOSE AND SCOPE OF THE RESOURCE PLANNING GUIDELINES

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. The Resource Planning Guidelines (the "Guidelines") outline a comprehensive process to assist the development of such plans.

The Utilities Commission Act ("UCA") was amended in 2003 to provide the Commission with a mandate to implement the policy actions of the Provincial Government's November 2002 energy policy, "Energy For Our Future: A Plan For BC" ("Energy Plan"). Amendments to Section 45 of the UCA expand upon and clarify the planning requirements of utilities and the Commission's role to review filed plans to determine whether expenditures are in the public interest and whether associated rate changes are necessary and appropriate. The additions to Section 45 of the UCA are as follows:

> 45 (6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission;
>
> (a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;
>
> (b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;
>
> (c) a plan of how the public utility intends to reduce the demand for energy and the expenditures required for that purpose.
>
> (6.2) After receipt of a plan filed under subsection (6.1), the commission may:
>
> (a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in the plan;
>
> (a) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility, and
>
> (b) determine the manner in which expenditures referred to in the plan can be recovered in rates.

On the basis of subsection 6.1, the Commission will require that any resource plans filed under paragraph 6.1, (a), (b) and (c) be prepared in accordance with the Guidelines.

The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources (including "BC Clean Electricity" as referred to in the Energy Plan), and those which focus on conservation of energy and Demand Side Management ("DSM").[1] Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The process aids in defining and

[1] *Demand Side Management* may be defined as a deliberate effort to decrease, shift or increase energy demand. Utilities develop DSM programs to encourage customers to enact DSM measures. Because of measurement difficulties and uncertainty about consumer behavior, DSM programs should be evaluated before and after implementation to determine their full impacts.

assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service.

In most circumstances, Certificates of Public Convenience and Necessity ("CPCN") applications should be supported by resource plans filed pursuant to Section 45 of the UCA. The Commission expects that resource plans will help facilitate the review of utility revenue requirements and rate applications.

The Guidelines do not alter the fundamental regulatory relationship between the utilities and the Commission. The Guidelines do not mandate a specific outcome to the planning process, nor do they mandate specific investment decisions. The Guidelines provide general guidance regarding Commission expectations of the process and methods for utilities to follow in developing plans that reflect their specific circumstances. More specific directions regarding resource plans will be provided to utilities on a utility to utility basis. Further directions may address issues regarding the elements of the resource plan or the underlying methodology. The Commission will review resource plans in the context of the unique circumstances of the utility in question. For this reason, the Guidelines do not distinguish between the circumstances of small and large utilities or between transmission and distribution utilities, nor do they prescribe specific planning horizons or approaches to resource acquisition. Although the Guidelines are not prescriptive in that sense, after review of a resource plan the Commission expects to be prescriptive on a utility by utility basis, as necessary, to facilitate cost-effective delivery of a reliable and secure supply that meets demand for a utility's service.

RESOURCE PLANNING GUIDELINES

1. Identification of the planning context and the objectives of a resource plan

Key underlying issues and assumptions that inform the planning context should be identified and discussed (e.g., reliability and security issues, risk factors, major uncertainties). Objectives include, but are not limited to: adequate and reliable service; economic efficiency; preservation of the financial integrity of the utility; equal consideration of DSM and supply resources; minimization of risks; compliance with government regulations and stated policies; and consideration of social and environmental impacts.[2]

2. Development of a range of gross (pre-DSM) demand forecasts

In making a demand forecast, it is necessary to distinguish between demographic, social, economic and technological factors unaffected by utility actions, and those actions the utility can take to influence demand (e.g. rates, DSM programs). The latter actions should not be reflected in the utility's gross demand forecasts.[3] More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered more likely than others. The energy end-use categories[4] used to analyze DSM programs should be compatible with those used in demand forecasting, so that at any point a consistent distinction can be made between demand with and without DSM on an end-use category-specific basis. Thus, the gross demand forecast should be structured in such a way that the savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast.

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[2] Bonbright, Danielsen and Kamerschen, (Principles of Public Utility Rates, 1988, Ch.8, p.165) suggest that the rates set by utility commissions invariably involve some discretionary judgment about the extent to which broader social principles should influence ratemaking. Because of social and environmental impacts, the rates charged by utilities may be allowed to deviate from those that would result from a rate determination based exclusively on financial least cost. The objectives to be addressed may be identified by the utility, intervenors, or government. The BC Utilities Commission interprets its jurisdiction as extending only to consideration of environmental and social impacts that are likely to become financial costs in the foreseeable future.

[3] In other words, gross forecasts represent an attempt to simulate markets in which the utility did nothing to influence demand. Of course, this is not entirely possible. Utilities will continue to require rate increases and existing DSM programs will affect demand as will already ordered rate design changes. However, the assumptions made with respect to these factors in estimating future gross demand should be clearly specified so that the effects of these assumptions may be distinguished from the effects of future utility actions designed to influence demand.

[4] The term *End-use categories* is intended to mean energy consumption by categories of end-user, such as industrial, commercial, or residential. Guideline No. 2 does not prescribe *end-use forecasting* or *end-use modeling*, but rather requests that forecast outputs and DSM results be organized and checked according to end-use categories.

3. Identification of supply and demand resources

Feasible[5] individual supply and demand resources, both committed and potential, should be listed. Individual resources are defined as indivisible investments or actions by the utility to modify energy and/or capacity supply, or modify (decrease, shift, increase) energy and/or capacity demand.

4. Measurement of supply and demand resources

Each supply-side and demand-side resource must be measured against the objectives established under Guideline No. 1. This includes identifying utility and customer costs (life cycle costs, impact on rates, etc.), associated risks, and lost opportunities.[6] Characterizing the feasible supply and demand resources could also include reporting how these resources perform[7] relative to specific social and environmental objectives. This can facilitate a more comprehensive understanding of the tradeoffs between objectives as they may be associated with various supply and demand resources. Supply and demand resource cost estimates should represent the full costs of achieving a given magnitude of the resource. These cost estimates may be represented as supply curves; i.e. graphs showing the unit costs associated with different magnitudes of the resource.

5. Development of multiple resource portfolios

For each of the gross demand forecasts, several plausible resource portfolios should be developed, each consisting of a combination of supply and demand resources needed to meet the gross demand forecast. The gross demand forecasts and the resource portfolios should cover the same period, generally 15 to 20 years into the future.

6. Evaluation and selection of resource portfolios

For each of the gross demand forecasts, the set of alternative resource portfolios that match the forecast are assessed against the objectives. Analysis of the tradeoffs between portfolios and how they perform under uncertainty will facilitate determining which portfolio performs best relative to the stated objectives. This process will lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts.[8]

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[5] Feasible resource options are defined as those options consistent with the objectives of the resource planning process, as established under Guideline No. 1. For example, government policy may rule out a particular technology or form of energy.

[6] *Lost opportunities* are opportunities that, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. Examples can include cogeneration opportunities that are available but not taken when renovating a pulp and paper mill, or additional insulation that is not installed in a new house.

[7] Performance measures may be quantitative or qualitative.

[8] Guidelines No. 4 through No. 6 may require an iterative process to account for any interdependencies.

7. Development of an action plan

The selection process in Guideline No. 6 provides the components for the action plan. The action plan consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years in order to meet the most likely gross demand forecast. The action plan should include a contingency plan that specifies how the utility would respond to changed circumstances, such as changes in loads, market conditions or technology and resource options. For resources with considerable uncertainty, the action plan should incorporate an experimental design and monitoring plan to allow for hindsight evaluation of associated market impacts and full resource costs.

8. Stakeholder input

Although utility management is responsible for its resource planning and resource selection process, utilities should normally solicit stakeholder input during the resource planning process. Methods could include stakeholder collaboratives, information meetings, workshops, and issue papers seeking stakeholder response. Utilities are encouraged to focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs.

9. Regulatory input

To streamline the regulatory process, utilities are encouraged to seek review and comment from Commission staff during the various phases of resource plan preparation.

10. Consideration of government policy

A resource plan filed in accordance with the UCA and these Guidelines should be consistent with government policy, as it is expressed in legislation (e.g. efficiency standards) or in specific policy statements and directives. Emerging policy issues, such as increased control of emissions, may be addressed as risk factors.

11. Regulatory review

Upon receipt of a resource plan filed pursuant to Section 45, paragraph 6.1, the Commission will establish a review process, as necessary, pursuant to Section 45, paragraph 6.2. A review may provide, as the Commission considers appropriate, opportunities for written and/or oral public comment.