REFERENCE:

QUESTION:

Billinton/Karki conducted a probabilistic assessment of the generation and transmission adequacy of the WAF system using the Loss of Load Expectation (LOLE) and the Loss of Energy Expectation (LOEE) reliability criteria. Did Billinton or Karki ever suggest to YEC to adopt a deterministic criterion?

ANSWER:

Yes. As set out in detail below, Dr. Billinton and Karki provided their inputs and suggestions as part of a workshop with YEC staff, which led to the conclusion that a combined probabilistic and deterministic criterion for the WAF system would be reasonable.

Professors Billinton and Karki conducted a study on the reliability of the WAF system "to identify key areas and system characteristics relevant for the review of the Required Firm Capacity Planning Criteria". This study resulted in two reports. The report dated February 2005 is focused on the existing system and on the future impact of generating unit retirements. The report dated June 2005 is focused on conditions in 1996, as these were the last conditions reviewed by the YUB. The two reports noted above did not recommend that YEC adopt a particular deterministic or probabilistic criterion. The analysis described in the February 2005 report used the WAF 1996/97 deterministic criterion to benchmark the probabilistic indices of LOLE and LOEE using the same general conditions under which the WAF 1996/97 deterministic criterion was established. The system model in this case is shown in Figure 3.1 of the February 2005 report.

The February 2005 report clearly shows the effect on the generating system reliability of the seasonal capacity limitations of the Whitehorse hydro units, the Aishihik transmission line and the impending retirements of the Mirrlees diesel units at the Whitehorse plant. The report also illustrates the vulnerability of the Whitehorse load centre to the loss of the Aishihik transmission line. This is described in Chapter 6 titled "Generating System Reliability Evaluation of the Whitehorse System".

The February 2005 and June 2005 reports provided the focus for discussion on the subject of deterministic and probabilistic criteria at a Workshop held in Whitehorse on

July 26 and 27, 2005. It was agreed that the current deterministic criterion did not adequately represent the underlying reliability of the system and that new criteria were required. The dual criteria of a LOLE of 2.0 hours/year for overall generating capacity adequacy assessment and a N-1 criterion for emergency conditions presented in the 20 Year Resource Plan 2006-2025 were proposed and determined to be reasonable at this Workshop, and were later approved by YEC's Board of Directors.

The general topology of the WAF system is very similar to the Snare-Yellowknife system in the Northwest Territories. As part of the July 2005 workshop, Dr. Billinton reviewed, with YEC, the approaches adopted by the NWT Public Utilities Board that included a combined probabilistic/deterministic approach, and provided background on his testimony in that case[1]. The Northwest Territories PUB subsequently approved dual criteria for the Snare-Yellowknife system (similar to those ultimately proposed by YEC in the 20 Year Resource Plan, 2006-2025). The NWTPC criteria are discussed further in YUB-YEC-2-2 and 2-7. Based in part on the experience in NWT, Dr. Billinton indicated to YEC that a similar approach utilizing both probabilistic and deterministic criteria for the WAF system would be reasonable.

[1] Dr. Billinton served as a consultant to NTPC and testified on the NTPC-Capacity/Reliability Planning Criteria Application. In that proceeding, the two-part criteria for the Snare-Yellowknife system (deterministic and probabilistic) was reviewed by the Board, and Dr. Billinton provided the Board with his assessment that the approach was reasonable and that the two criteria were not in conflict.

REFERENCE:

QUESTION:

The February 2005 Billinton/Karki Report found that a 1.15 days/year LOLE or a 3.903 MWh/year LOEE resulted in the same load carrying capacity as the WAF deterministic 1996/97 criteria. The Resource Plan indicates (pages 3-20) that typical LOLE values commonly used by other Canadian utilities range from 1 to 2 days/year.

a) Please explain YEC's rationale for adopting the 2 days/year LOLE instead of 1 day/year, which is much closer to the 1.15 days/year found by Billinton/Karki
b) If the WAF deterministic 1996/97 criteria is not providing adequate generating capacity, why not adopt a more stringent 1 day/year LOLE instead of the less stringent 2 days/year LOLE?
c) Why did YEC decide not to adopt a LOEE-based criterion?

ANSWER:

YEC assumes the questions are meant to reference 2 hours/year LOLE, not 2 days/year.

a)

The decision to use 2 hours/year LOLE was based on YEC’s judgment about the WAF system. In making this decision, YEC considered as a primary factor the decision to use 2 hours/year as the comparable criteria in NWT (in conjunction with the N-1 deterministic criteria).

YEC also recognized that the LOLE criterion was not to operate in isolation but in conjunction with the N-1 criteria which offers specific protection to address the Aishihik line-related risks.

The LOLE value of 1.15 hours/year shown in the February 2005 report by Professors Billinton and Karki is a benchmark value obtained using the maximum allowable peak load (MAPL) under the 1996/97 deterministic criterion and the general system conditions covered by the 1996/97 deterministic criterion. The LOLE value of 1.15 hours/year is an important benchmark and lies within the range of LOLE values used in other jurisdictions. Table 1.1 in the February 2005 report shows the criteria used by Canadian electric power utilities. The LOLE criteria range from 0.1 to 0.2 days/year and are roughly equivalent to 1.0 to 2.0 hours/year. It should be noted that Hydro Quebec specified a LOLE of 2.4 hours/year. The LOLE of 2.0 hours/year proposed by YEC is therefore on the upper end of the range illustrated in Table 1.1 and is considered to be a reasonable and practical criterion for YEC generating capacity planning. The Northwest Territories PUB also approved a LOLE criterion of 2.0 hours/year for the NWTPC Snare-Yellowknife system.

b)

As set out at page 3-19 of the Resource Plan, the previous WAF deterministic criteria does not provide sufficient protection as it would allow the system to approach 5.9 hours/year LOLE without indicating a need for new generation.

The February 2005 report shows that the MAPL under the 1996/97 deterministic criterion is 68.7 MW. The MAPL as a function of the LOLE is shown in Figure 4.4 of the report. The MAPL for a LOLE of 1.0 hour/year is 60.0 MW and for a LOLE of 2.0 hours/year is 62.9 MW. Both values are considerably lower than the MAPL obtained using the 1996/97 deterministic criterion due to the incorporation of the seasonal constraints and the Aishihik transmission line. The criterion of an LOLE of 1 hour/year is obviously more stringent than using a LOLE of 2.0 hours/year but both criteria are considerably more stringent than the 1996/97 deterministic criterion.

c)

The YEC decided to adopt a LOLE-based criterion, as historically, it is the most widely used index and is relatively easy to understand and appreciate. It has also been accepted by the Northwest Territories PUB for application by NTPC.

Also see YUB-YEC-1-12 in regards to YEC's rationale for not adopting an LOEE based criteria.

REFERENCE:

QUESTION:

The February 2005 Billinton/Karki Report indicates that industry-typical Forced Outage Rates (FOR), namely 3% for hydro and 10% for diesel plants, were used in the LOLE calculation. The Conclusions (Section 7) of the February 2005 Billinton/Karki Report states that it is important to obtain actual system and equipment specific data for realistic reliability evaluation and strongly recommends that a routine data collection scheme be established to record system events involving generation and transmission equipment forced outages and the relevant failure and repair data be extracted and compiled on an annual basis. In this regard:

a) Is the lack of system-event historical generation data for YEC's and YECL's generating units the reason why YEC used industry-typical FORs rather than the FORs derived from actual records?
b) Has YEC implemented this recommendation?
c) If yes, do the FORs computed using data collected to date show significant discrepancies from the industry-typical FORs used?

ANSWER:

a)

Yes[1]. With respect to YEC's own data, Attachment YUB-YEC-1-3(e) shows the individual unit unavailability data for the 1999/2005 period.

b)

YEC is implementing this recommendation in two stages:

- Stage 1 was to convert existing operating information into one common database. Prior to this it been stored in a number of spreadsheets and work documents. This work was completed in March of 2006.

[1] Note, however, that YEC also has concerns that even if perfect data were available for its own systems performance in past years this data may not form a large enough "sample set" of performance to provide suitable predictive value. This is because, for example, YEC only has 6 hydro units on its system in the CEA range above 5 MW, whereas the CEA data set tracks 175 such units. Similar concerns arise with respect to kilometers of transmission, where YEC's own complement is very small compared to the CEA data.

- Stage 2 is to add additional information and calculated values to this data base that will allow further separation and analysis of operating data. For example, YEC currently tracks all generating unit statuses as operating, available-but-not-operating and out-of-service. The stage two work will further breakdown out-of-service to planned and unplanned. An unplanned out of service event is a forced outage which will then be tracked separately.

c)

YEC does not have sufficient data from its own systems over any sufficient period to indicate whether there are variances between its data and the CEA data.

REFERENCE:

QUESTION:

In response to YUB-YEC-1-3(b), YEC indicates that the load data used in the LOLE calculations was hourly load data (as shown on page 13 of the Billinton/Karki main report) and that the model used all the hourly values in a seasonal or annual period. YEC also included chronological loads from February 2, 1999 to January 31, 2004, in YUB-YEC-1-3 Attachment 3B. In this respect:

a) Please confirm that the LOLE calculations were conducted over a two-season period, namely a summer season (April to October) and a winter season (November to March), as stated on page 3 of the June 2005 Billinton/Karki Report.
b) If yes, were the Load Durations Curves (LDC) shown on Figure 2.4 of the February 2005 Billinton/Karki Report the ones used in the model?
c) The chronological load data provided in YEB-YEC-1-3 Attachment 3B does not include February 2004 to March 2004, so we are unable to produce the 2003-2004 November to March winter season LDC. Please provide this load data.
d) Page 13 of the February 2005 Billinton/Karki Report indicates that the annual load factor was 56.8%. However, the June 2005 Billinton/Karki Report indicates (on page 4) an annual load factor of 64.59%. Please explain why different load shapes were used in these reports.
e) Please clarify which load shape (the 56.8% or the 64.59% load factor) was used in the calculations of Load Carrying Capacity (LCC) at 2 days/year LOLE that appear on Table 3.5 (page 3-24) of YEC's Resource Plan?

ANSWER:

a) and b)

Separate load models were created for the summer and winter seasons. The summer period is from April to October and the winter period is from November to March. The average seasonal load duration curves based on the five annual periods, as shown in Figure 2.4, were used in the studies in the February 2005 report. The seasonal load models shown in Figure 2 were used in the June 2005 report.

The LOLE and LOEE values in Chapters 2 and 3 of the February 2005 report were obtained by summing the two seasonal contributions. The summer season contribution is less than 0.4% of the annual LOLE due to the increase in the Whitehorse hydro capacity and the decrease in actual load levels. Only the winter season contribution was used in the results shown in the remaining chapters of the February 2005 report. As an example, the winter and summer LOLE contributions respectively for a peak load of 60.0 MW in Figure 4.2, are 1.0045 and 0.0032 hours/year for an annual total of 1.0077 hours/year. The summer contribution is 0.32% of the annual value in this case.

The initial results in the June 2005 report (Tables 5 and 6) were obtained using both seasonal models. The plots in Figure 4 and 6 were created using the winter period values.

c)

The chronological load data for February 2004 to March 2004 are attached in the excel file YUB-YEC-2-4 Attachment 1. However the data provided to Billinton/Karki was that provided in YUB-YEC-1-3 Attachment 3b.

d)

The June 2005 Billinton/Karki report is based on the conditions that existed on the system in 1996/97 when the Faro mine was operating (the last time the WAF criteria was reviewed by the YUB). At that time, the system operated at a considerably higher load factor.

e)

The YEC Resource Plan uses the load factors representative of today's system, not the system as it existed in 1996/97.

REFERENCE:

QUESTION:

Please explain why the most recent June 2005 Billinton/Karki Report uses maximum continuous ratings (MCR) of 4 MW for unit WD1 and 5 MW for units WD2 and WD3, while the less recent February 2005 Billinton/Karki Report uses MCRs of 3 MW for Unit WD1 and 4.2 MW for units WD2 and WD3.

ANSWER:

The June 2005 Billinton/Karki Report uses MCRs for the total installed capacity of the Whitehorse-Aishihik-Faro Grid as it existed in 1996-1997. This is 4 MW for unit WD1 and 5 MW for units WD2 and WD3. These are the basic nameplate values for the units.

The February 2005 Billinton/Karki Report uses MCRs of 3 MW for WD1 and 4.2 MW for WD2 and WD3 because these are the derated values for these units YEC has adopted given their current condition and output constraints. YEC’s expectation is that once the Mirrlees Life Extension is completed on the units they will be capable of their full MCR values.

REFERENCE:

QUESTION:

Page 2-17 of the Resource Plan states: "Since the Faro Mine closure in 1998, a 5 MW diesel unit was retired at Faro. Two diesel units with a combined capacity of 2 MW were moved to Mayo, and a 1.3 MW unit was removed from Faro to act as a mobile unit. The result is a decrease in the Faro diesel plant size from 13.6 MW to 5.3 MW; in addition, two diesel units with a combined capacity of 1.3 MW were retired from Mayo."

a) Please explain why the most recent June 2005 Billinton/Karki Report includes 7 units at Faro.
b) Has the 1.3 MW unit, which was removed from Faro to act as a mobile unit, been accounted for in the Resource Plan? If no, please explain why. Can this mobile unit be installed back on the WAF grid to help alleviate the capacity shortfall?
c) Given that the MD grid does have surplus capacity for the foreseeable future, has YEC considered returning one or both diesel units that were moved from Faro to Mayo, back to Faro?

ANSWER:

a)

The June 2005 Billinton/Karki report assesses the system as it existed in 1996/97. At that time Faro had 7 units. Since that time 4 units have been retired or relocated as set out in the question above, leaving 3 units today (as shown at Table 3.3 of the Resource Plan).

b)

No. This unit is not included in WAF firm capacity planning as it is not routinely connected to the WAF system and as such is at most an emergency backup unit (i.e., a means to help address the impacts of major sustained outage conditions, not a means to help avoid loss of load in the first place). Under normal conditions, this unit is used for maintaining service during planned maintenance on transmission or generation, such as providing supply to loads connected to individual PT sites when the transmission line out of service for planned maintenance. It can also be dispatched to support YEC customer loads during potential sustained line outages (such as at smaller centres like Johnson's Crossing). It is not configured today for ready connection to the WAF system (it can be quickly connected to MD)

c)

No. The diesel units currently in Mayo (as set out in Table 3.3 of the Resource Plan) were located there to backup the potential for loss of hydro supply due to substation or other potential hydro plant issues. They continue to be required for this purpose.

REFERENCE:

QUESTION:

YEC indicates (YUB-YEC-1-2) that it is aware of only one other utility that uses a two-part criterion as YEC, namely the Northwest Territories Power Corporation (NTPC), and (page 3-21 of the Resource Plan) that YEC's proposed two-part capacity planning criterion is essentially the same as the capacity criteria approved by the regulator for the Yellowknife system. In this respect:

a) Has the Yellowknife system also adopted a LOLE criterion?
b) If yes, is it also 2 days/year or different?
c) If yes, is it calculated in the same manner as YEC's proposed LOLE? Specifically, is it also calculated over an 8760-hour period, does it account for seasonal capacity derates, no planned maintenance, and does it account for transmission outages similar to YEC's Aishihik/L171 multi-state model?

ANSWER:

YEC has not proposed the criteria set out in the Resource Plan, it has already adopted these criteria for the system, and they form the basis for YEC's planning activities.

a)

Yes.

b)

YEC assumes the question is meant to reference 2 hours/year not 2 days/year. Yes, NTPC has adopted 2 hours/year LOLE.

c)

The Northwest Territories PUB approved the NWTPC firm capacity planning criteria for the Snare-Yellowknife Zone with the following Board Order:

> A long-term target loss of load expectation ("LOLE") of 2 hours per year using the Snare-Yellowknife System Reliability Evaluation Program ("SYSREP") generation and transformation/transmission approach at the Yellowknife load point, subject to engineering judgement.

Yellowknife load point minimum diesel: 105% of the Yellowknife load point forecast, without Con and Giant mine load, met with the primary supply out of service, where the primary supply is the Snare hydro (i.e. only Jackfish and Bluefish units in service), subject to engineering judgement.

The approach used in SYSREP is conceptually identical to that applied in the analysis described in the February 2005 report by Professors Billinton and Karki. The annual LOLE is calculated over an 8760 hour period and can include, if necessary, seasonal capacity derates and planned maintenance. The transmission line between the Snare hydro plants and Yellowknife is considered and incorporated in the analysis in a similar manner to that used to incorporate the Aishihik transmission line in the WAF system analysis described in the February 2005 report.

See the attached information, which includes a copy of the April 21, 2004 NTPC Application to the NWT PUB (YUB-YEC-2-7 Attachment 1), and a copy of NWT PUB Decision 14-2004 (YUB-YEC-2-7 Attachment 2).

NORTHWEST TERRITORIES
POWER
CORPORATION
Financial Planning & Coordination, 4 Capital Drive, Hay River NT X0E 1G2 *Phone (867) 874-5200 Fax (867) 874-5251*

April 21, 2004

Mr. John Hill, Chairman
Northwest Territories Public Utilities Board
203-62 Woodland Drive
Box 4211
Hay River, NT X0E 1G1

Dear Mr. Hill,

Re: Capacity/Reliability Planning Formulae

In accordance with Board Decision 1-2002, this submission addresses the requirement for the Northwest Territories Power Corporation ("NTPC" or the "Corporation") to apply to the Public Utilities Board ("PUB") for resolution of the Snare-Yellowknife Zone Capacity Planning Criteria, and the capacity planning criteria for Rae/Edzo, Inuvik, Fort Smith, Norman Wells and Fort Resolution. NTPC has also re-submitted the capacity planning criteria for isolated diesel systems in order to have the full slate of planning criteria approved as a package.

The Corporation is requesting an Order of the Board approving the following required firm capacity planning criteria for all NTPC communities:

- **Isolated Diesel Systems:** ensure that 110% of the forecast peak load can be met with the largest single unit out of service, subject to engineering judgement.
- **Dual Fuel Communities:** ensure that 105% of the forecast peak load can be met with the primary supply out of service, subject to engineering judgement. The primary supply for the dual fuel communities is as follows:
  - **Fort Smith and Fort Resolution:** The Taltson hydro supply
  - **Norman Wells:** The purchased power supply
  - **Inuvik:** The gas pipeline supply
  - **Rae/Edzo and Yellowknife:** The Snare hydro supply (see Snare-Yellowknife zone below)
- **Snare/Yellowknife Zone:** achieve a long-term target LOLE of 2 hours/year (using the SYSREP Generation and Transmission/Transformation approach) at the Yellowknife load point. Also, for each load point the following specific criteria:

- **Yellowknife minimum diesel:** require the supply available to be able to carry 105% of the forecast peak loads at the Yellowknife load point (exclusive of the mines) with all Jackfish and Bluefish units in service (i.e., with the Snare hydro transmission supply out of service) subject to engineering judgement.
- **Rae/Edzo minimum diesel:** ensure that 105% of the forecast peak load can be met with the Snare hydro transmission supply out of service, subject to engineering judgement.

Consistent with the planning criteria previously used by the Corporation, either a 5% or 10% safety factor is applied to deterministic calculations to accommodate the risk of forecast error. Also, in each case, NTPC is requesting that the planning criteria also incorporate provision for *engineering judgement*. Engineering judgement is applied to determine when to install additional capacity and what amount of capacity to install. Examples of engineering judgement were discussed in YK-NTPC-108 from the 1995/98 Phase I application, and include such things as:

- engine and generator ratings and related information provided by the manufacturer;
- engine and generator age, including considerations of both operating hours and years in service;
- engine and generator condition, including consideration of operating and maintenance history, as well as manufacturers original specifications;
- genset control system condition, including consideration of type of governor and whether manual or automatic control;
- genset auxiliaries condition, including condition of the jacket-water cooling, combustion air handling and fuel delivery systems;
- shape of the load duration curve and other relevant load data and information;
- experience of onsite operators and availability of maintenance personnel and backup equipment;
- the potential availability of portable and third party generation;
- the potential availability of customers who can interrupt part of their load if required; and,
- the sizing of the power plant to be installed will likewise require judgement of similar factors to those noted above, as well as such factors as load growth expected, economy of operation (fuel efficiency, etc.) and ease of maintenance;
- other relevant data and information relating to the particular circumstances of the plant and community in question.

Final approval of the planning criteria will satisfy paragraph 15 of the 2001/03 GRA Phase I negotiated settlement, and ensure all parties have clarity as to the planning formula that will be used in long-term system planning of the NTPC's system.

As the issues in this filing extend to all customers served by the Corporation, we have copied this submission to all interested parties in the 2001/03 GRA.

INTRODUCTION

All parties involved in planning or regulating electrical power systems have an interest in ensuring the bulk power system is sufficiently reliable over the long-term to meet the reasonable expectations of customers in regards to supply, while at the same time being planned in a manner that is economically prudent and not incurring excessive costs to achieve a level of reliability that is in excess of what is required. These somewhat competing objectives are present for all interested parties – a desire for an adequately high level of reliability, without pursuing unnecessary increases in reliability at excessive additional costs.

The review of the NTPC's capacity planning criteria dates back to the Corporation's 1992/93 GRA. The planning criterion for Yellowknife in particular has been developed over more than a decade. At the Corporation's 1992/93 GRA, the PUB ordered NTPC to investigate the existing planning criteria and determine what changes are required. The history of the Yellowknife capacity planning issue is set out in Attachment A

NTPC plans and manages a number of different kinds of systems. For planning purposes, it is helpful to think about the systems as being of three types of increasing complexity: Isolated Diesel Systems, Dual Fuel Systems, and the Snare-Yellowknife Zone[1]. Each of these is addressed below.

ISOLATED DIESEL SYSTEMS

NTPC's isolated diesel systems are planned to ensure that 110% of the forecast peak load can be met with the largest single unit out of service. As noted in the Corporation's 2001/03 GRA, engineering judgment is applied to determine when it would be appropriate to rely upon the potential availability of portable and third party generation to avoid making or to postpone capacity additions when the installed capacity is only slightly below the criteria. Engineering judgement is also a major influence in deciding the size and configuration of the units to be installed. This planning criterion was approved by the 2001/03 Phase I Negotiated Settlement, as approved by the Board in Decision 1-2002.

DUAL FUEL COMMUNITIES

For a group of communities that rely on two distinct sources of generation supply, noted in the 2001/03 GRA as Fort Smith (Taltson hydro and local diesel), Fort Resolution (Taltson hydro and local diesel), Rae/Edzo (Snare hydro and local diesel), Norman Wells (purchased power and

[1] The Taltson zone is not planned as a zone. No hydro capacity changes have taken place for some time and none have been forecast or assessed for domestic supply. In that zone, each of Fort Smith and Fort Resolution have separate system planning criteria based on their respective installed diesel plants, and NUL supply at Hay River is not specifically addressed in system expansion planning. NTPC does not have an obligation to provide power in Hay River.

local diesel) and Inuvik (natural gas and local diesel), a different planning criteria is required. In those cases, the Corporation proposed in the 2001/03 GRA to plan for a diesel plant that is able to supply 105% of the forecast peak when the primary (hydro, purchased power or gas) supply is out of service. In Decision 1-2002, the Board directed NTPC to review the planning criteria for each dual fuel community in light of its particular circumstances and re-file the planning criteria for dual fuel communities at the time the Snare-Yellowknife criteria were filed, specifically noting the particular circumstances for each community. The Board questioned whether a difference in the reliability level of the primary supply source should be recognized to the extent it is material.

The Corporation has reviewed the Board's concerns. As discussed below, there are specific uncertainties and risks associated with supply from each of the dual fuel communities' primary supply source that justify the Corporation's proposed criteria.

Rae/Edzo and Yellowknife are addressed below in conjunction with the Snare-Yellowknife system. For the other 4 dual fuel communities, the following sets out the required information:

- ***Fort Smith and Fort Resolution:*** In these two communities, supply comes primarily from the Taltson hydro plant, except for periods of hydro or transmission line outages, or periods of shutdown. As the Taltson hydro plant only generates notable power out of the single generator, outages for servicing (typically in summer) are required to be met by potentially extended use of diesel. As a result, these plants are both required for winter backup and for summer maintenance shutdowns.

- ***Norman Wells:*** The town of Norman Wells is primarily supplied by purchased power from Imperial Oil. Although supply from Imperial is very reliable and has its own internal redundancies, the Corporation cannot control or dispatch the generation. In addition, there have been discussions regarding the likely length of time the Corporation can expect to be served by Imperial, and although there have been no decisions made, the supply is not indefinite. As a result, the Corporation's diesel plant must be available for purchased power supply unavailability.

- ***Inuvik:*** The town of Inuvik receives generation from both natural gas (via a small pipeline that services the town) and diesel generation. The current complement of natural gas generation in Inuvik is not large enough to carry the winter peak, so diesel is used for both peaking generation and gas outages. The Corporation's gas supply comes from a single non-redundant well and pipeline system. As a result, the Corporation's diesel plant must be available to supply 105% of the Inuvik peak load with the gas pipeline supply out of service.

As a result of application of this criterion, NTPC's dual fuel communities will achieve a standard of reliability that is similar to isolated diesel systems.

SNARE YELLOWKNIFE ZONE COMMUNITIES

For the Snare-Yellowknife zone communities, which comprise Yellowknife, Dettah and Rae/Edzo, the supply is similarly "dual fuel" as it is separately derived from hydro (primary) and diesel (backup and peaking). For this system, three separate reliability considerations must be addressed. The first is the reliability of the integrated system, and the second and third relate to the reliability of the City of Yellowknife and Rae/Edzo respectively when the key L199 transmission line is out of service.

1. ***Snare-Yellowknife Zone:*** The reliability of the Snare-Yellowknife zone is a complicated assessment of multiple generation sources, transmission line components and transformation units. Questions regarding the reliability criteria for the zone were the primary reason for the last 10 years of study of NTPC's reliability criteria. In order to assist with this assessment, starting in the early 1990's the Corporation retained a respected system planning expert, Dr. Billinton of the University of Saskatchewan. Dr. Billinton provided advice on the planning criteria and developed the SYSREP (or Snare-Yellowknife System Reliability Evaluation Program) model. SYSREP is a simplified representation of the Snare-Yellowknife system. SYSREP allows the reliability of the system to be calculated based on the probability of outages of various units on the grid, compared to the peak loads expected to be served.

   The model uses a probabilistic approach, much like that used by the more complicated interconnected grid systems in southern Canada. The final output of the model is a measure commonly used by other utilities called a Loss of Load Expectation (LOLE), measured as expected number of hours in the specified period when a loss of load occurs. Southern utilities commonly plan systems to a reliability LOLE of between 1-2 hours/year.

   A detailed discussion of the SYSREP model and the various ways it can be used is set out in Attachment B. The most appropriate approach to modelling the Snare-Yellowknife system considers the unique nature of the Snare-Yellowknife system (compared to southern grids), which is the transmission service is non-redundant. In that regard, SYSREP is not limited to considering the output of each generating unit and the likelihood of each generating unit of actually being available when it is needed, but it also considers the probability of an outage on the transmission lines and key transformation.

   The consideration of transmission and transformation in calculating LOLE is not the norm in southern Canada, where redundant transmission networks and substations are the norm. However, in NWT the non-redundant transmission linkages become key factors in the ability of a generation system to deliver power. Addition of the transmission and transformation components to the model allows the LOLE in the NWT to be effectively compared against the LOLE for southern utilities. However, this approach also results in a unique limitation on the SYSREP compared to southern utilities. That is, the SYSREP LOLE is the measured reliability at the Yellowknife load point, once the generation has been delivered by the transmission lines and key Yellowknife-area transformation units. In southern Canada, LOLE is relevant for all load points, not limited to a measure of reliability at a single load point. This component of the SYSREP assessment ignores the loads and generation at the Rae/Edzo load point, but as Rae/Edzo makes up well under 5% of the system, and it is serviced by its own backup generation, this treatment is consistent with approaches used in other jurisdictions for small "interruptible" loads. SYSREP was not designed to and cannot assess the ability of the transmission and transformation system to deliver power to the Rae/Edzo load point.

NTPC proposes that the LOLE value be targeted over the long-term to achieve a measured value of 2 hours/year. This is similar to the 2 hours/year LOLE value traditionally used for the Alberta Interconnected System[2].

With the forecast closure of the mines, the LOLE is expected to drop to below this target in the next few years. This target is not designed to lead to generation additions in the near term, but to be taken into account assessing plant additions, replacements or changes to configuration over the long-term.

In summary, the reliability of the Snare-Yellowknife system (as currently configured) offers to Yellowknife an LOLE is as follows:

Table A: SYSREP output

Yellowknife load point (MW) actual/forecast peak	LOLE considering Generation, Transmission and Transformation (hours/year)
2001/02 – 39.3*	14.27
2002/03 – 39.8*	16.06
2003/04 – 37.8*	10.32
2004/05 – 38.5	2.94
2005/06 – 32.2	1.08
2006/07 – 33.6**	1.56
2007/08 – 34.2**	1.80
2008/09 – 34.9**	2.11

*Load data does not include Bluefish capacity as the Corporation did not have control over the generating station at that time.

**Load data does not include the Ruston diesel unit as it is scheduled for decommission in 2005/06.

[2] By comparison, the most typical LOLE target for southern Canadian utilities is 1 hour per year (includes Manitoba Hydro, BC Hydro and Nova Scotia Power) or 2 hours per year (the Alberta Electric Interconnected System and Newfoundland Hydro).

2. ***The Yellowknife Load Point Minimum Diesel:*** The key reliability factor for Yellowknife is the L199 transmission line. The loss of the transmission line results in the loss of all the hydro generation on the Snare River (23.7 MW), the key reliability linkage for supply to the Yellowknife load point is identified to be the L199 transmission line. This single line carries upwards of 50% of the generation capacity on the system. The output of the SYSREP probabilistic model indicates that almost the entire LOLE for the Yellowknife load point arises due to potential outages of the L199 transmission failures (not generation plant problems).

   In developing the SYSREP model and the LOLE targets, it became apparent to NTPC that the supply to Yellowknife in the future (with the mines closed and Bluefish under NTPC control) will be primarily constrained by transmission line outages. The probabilistic model can determine the likelihood of such an outage, but it does not provide any practical guideline as to the amount of generation that should be maintained in the local Yellowknife area to deal with these outages. Although NTPC did not set out to develop a deterministic minimum diesel criterion for Yellowknife, it has become increasingly apparent that such a criteria is needed to ensure NTPC can provide adequate supply. As a result, it is prudent to ensure that Yellowknife has a core ability to supply the local load using other resources not dependent on the L199 transmission line, which are the Jackfish diesel plant and the Bluefish hydro plant.

   NTPC is proposing a planning criteria for the Yellowknife load point that will require the supply available to be able to carry 105% of the forecast peak loads at the Yellowknife load point (exclusive of the mines) with the L199 out of service (all Jackfish and Bluefish units in service). This criteria is currently being met, as illustrated in Table B below, and is consistent with the proposal in regards to the dual fuel communities.

Table B: Yellowknife Minimum Diesel

Yellowknife load point actual/forecast peak (without the mines)	Required Firm Capacity		Actual Reserve
(MW)	(%)	(MW)	(%)
2001/02 – 26.5*	105%	27.8	107%
2002/03 – 26.9*	105%	28.2	105%
2003/04 – 25.5*	105%	26.8	111%
2004/05 – 28.9	105%	30.4	120%
2005/06 – 29.4	105%	30.9	111%
2006/07 – 30.7**	105%	32.2	107%
2007/08 – 31.3**	105%	32.9	104%
2008/09 – 32.1**	105%	33.7	102%

*Load data does not include Bluefish capacity as the Corporation did not have control over the generating station at that time.

**Load data does not include the Ruston diesel unit as it is scheduled for decommission in 2005/06.

3. ***Rae/Edzo Minimum Diesel:*** Rae/Edzo is supplied primarily by the output of the Snare hydro plants (similar to the communities of Fort Smith and Fort Resolution), and a diesel plant is maintained at Frank's Channel for backup. The primary supply via the transmission line is subject to outages of either the main L199 line, or the much older line that brings power from the L199 Smiley Lake tap to the community (which was built around 1970). Since Rae/Edzo is a small community, there are few options to aid in restoring service (such as readily interrupted loads). As well, Rae/Edzo cannot rely on the large diesel generators at the Jackfish station in Yellowknife, because transmission supply interruptions isolate the community from that generation at the same time as the Snare hydro (as well, the system is not configured to allow power to flow "backwards" from Yellowknife to Rae/Edzo). As a result, Rae/Edzo's diesel plant is required for outages to supply the community's forecast peak. The current Frank's Channel configuration is slightly undersized for the forecast peak, so a larger generating unit is planned for installation in 2004/05.

Applying this approach to assessment of the Snare-Yellowknife system reflects a balanced two-part perspective of the current Snare-Yellowknife configuration, as follows:

- The Snare-Yellowknife system generating and transmission plant as currently installed is capable of providing an acceptable level of reliability (LOLE) to the Yellowknife load point, so no new major investment to expand diesel capacity (with the exception of Rae/Edzo backup diesels) or further improve transmission/transformation is likely required in the next several years for capacity reasons.

- The Snare-Yellowknife system generating and transmission plant as currently installed is not in excess of what is required for servicing the loads that exist at Yellowknife and loads expected for the next number of years.

SUMMARY

In summary, as noted at page 2, the Corporation is proposing the following required firm capacity planning criteria set out at page 2:

- **Isolated Diesel Systems:** ensure that 110% of the forecast peak load can be met with the largest single unit out of service, subject to engineering judgement.
- **Dual Fuel Communities:** ensure that 105% of the forecast peak load can be met with the primary supply out of service, subject to engineering judgement. The primary supply for the dual fuel communities is as follows:
    - **Fort Smith and Fort Resolution:** The Taltson hydro supply
    - **Norman Wells:** The purchased power supply
    - **Inuvik:** The gas pipeline supply

  - **Rae/Edzo and Yellowknife:** The Snare hydro supply (see Snare-Yellowknife zone below)
- **Snare/Yellowknife Zone:** achieve a long-term target LOLE of 2 hours/year (using the SYSREP Generation and Transmission/Transformation approach) at the Yellowknife load point. Also, for each load point the following specific criteria:
  - **Yellowknife minimum diesel:** require the supply available to be able to carry 105% of the forecast peak loads at the Yellowknife load point (exclusive of the mines) with all Jackfish and Bluefish units in service (i.e., with the Snare hydro transmission supply out of service) subject to engineering judgement.
  - **Rae/Edzo minimum diesel:** ensure that 105% of the forecast peak load can be met with the Snare hydro transmission supply out of service, subject to engineering judgement.

For future plant additions related to the reliability of service, the Corporation will use the above criteria (including the probabilistic output of the SYSREP model) to assist in determining the system requirements, and will provide this output to the Board and intervenors as required for regulatory review (such as Capital Project Permit Applications).

If you have any questions, please contact me at (867) 874-5234. Thank you for your attention to this matter.

Sincerely,

Judith Goucher
Director, Finance & CFO

cc: Interested Parties

ATTACHMENT A - HISTORY OF THE YELLOWKNIFE CAPACITY/PLANNING CRITERIA

During the regulatory review of NTPC over the course of a number of GRAs, the formula used to determine the required installed capacity (RIC) for the Snare-Yellowknife system has been addressed by the Public Utilities Board (PUB) and interveners. Specifically, this includes the following NTPC applications:

1992/93 GRA: The Yellowknife RIC formula in place at the time of the 1992/93 GRA was equal to 5% over annual peak system load with the largest generating unit out of service (the generating capacity of each unit is defined as the manufacturer's maximum continuous ratings). Intervenors disagreed with the formula and requested the Board to order NTPC to retain an outside consultant to review the formula. Intervenors also disagreed with the NTPC calculation of current installed capacity in that it did not include the 5 MW of gas turbine capacity stationed at Jackfish GS. In Board Order 9-93, the PUB required NTPC to retain an outside consultant to review the formula and provide recommendations as to any changes that may be required.

1993/94 GRA: The Yellowknife RIC formula was again addressed at the 1993/94 GRA. In their application (in response to Board Directive #3), NTPC filed a report prepared by system planning expert Dr. R. Billinton in regards to the capacity formula used by NTPC. In this report, Dr. Billinton recommended that the Yellowknife system move to a 'probabilistic' formula approach rather than the deterministic formula then in place (i.e. 5% over annual peak with the largest unit out of service).

During the hearing, NTPC undertook to provide the Board with a report of NTPC's progress towards a probabilistic approach to RIC on the Yellowknife system by the time of the next NTPC GRA. The Board issued Directive #1 which required NTPC to provide an assessment of the reserve requirement for Yellowknife using a probabilistic technique similar to that used by other Canadian utilities.

1995/98 GRA: During the negotiated settlement, the RIC formula was addressed. NTPC and Interveners agreed that a working group would be set up to address the question of a probabilistic approach to calculating RIC. Specifically, the settlement states:

> A NWTPC/Customer Capacity/Reliability Working Group would be established to agree on a "capacity/reliability planning formula" to be utilized by the Corporation in future General Rate Applications ... The work product of the Working Group would be reviewed in detail during the Corporation's next General Rate Application

The PUB, in Decision 1-97, acknowledged the establishment of the Capacity/Reliability Planning Working Group to "develop a capacity/reliability planning formula to be utilized by NWTPC in future General Rate Applications".

Working Group: Over the course of the Working Group since 1997, it has comprised members representing NTPC, the City, NUL, Royal Oak Mines and Miramar Mining. Royal Oak and Miramar are no longer engaged in the group. The Working Group met or held conference calls on the following occasions:

- June, 1997
- December, 1997
- December, 1998
- June, 2002
- February, 2004

The Working Group has also exchanged considerable information via an informal interrogatory process and discussions outside of the main meeting dates.

The Working Group has been assisted by technical analysis from Dr. Roy Billinton of the University of Saskatchewan and his associates. Dr. Billinton was retained by NTPC to assist in developing a probabilistic planning criteria for the Snare Yellowknife system in 1993.

2001/03 GRA: In NTPC's 2001/03 Phase I GRA, NTPC submitted its proposed Required Firm Capacity planning criteria. The negotiated settlement on that application noted:

> The Corporation withdraws the proposed capacity planning criteria for the Snare-Yellowknife zone (Section 2.5c of the Application). The Intervenors agree to diligently and in good faith pursue further discussions with a view to resolving their differences by October 1, 2002. In the event that an agreement among all interested parties is not reached by such date, the Intervenors agree that the Corporation may make application to the Board to have the Board resolve the issue.
>
> As a part of the discussions, the Corporation will provide cost estimates for alternatives to achieve improvements in LOLE.

The deadline for completion of the Working Group's assignment was extended to March 31, 2004, but the Working Group was unable to achieve a consensus and has now completed its activities.

ATTACHMENT B – DESCRIPTION OF THE SYSREP MODEL

BACKGROUND

Probabilistic techniques can be used to find the level of adequacy associated with a given generating capacity, and in certain cases transmission/transformation composition, and to calculate the plant required to provide a criterion level of adequacy. The probabilistic techniques evaluate historical outage data from all components of the electrical system and calculate the probability that those components will not be available when needed – the probability of an outage. The deterministic approach only considers the availability of a generating unit. The probability of an outage is called the forced outage rate (FOR). The FOR is used to calculate the risk of capacity shortage, expressed in terms of indices.

The basic function of an electric power system is to supply the customer load requirements as economically as possible and with a reasonable assurance of continuity and quality. The ability to generate the required energy is an integral component in the provision of an acceptable level of supply reliability. The generation facilities should then be matched with an appropriate transmission network such that the overall reliability of the composite generation and transmission system provides an acceptable level of reliability at the bulk system supply points.

A wide-range of indices have been developed to quantify the reliability of electric power systems. The most commonly used indices in generating capacity reliability evaluation are:

i) Loss of Load Expectation (LOLE): The expected number of hours in the specified period when a loss of load occurs.
ii) Loss of Energy Expectation (LOEE): The expected energy not served as a result of system deficiencies.

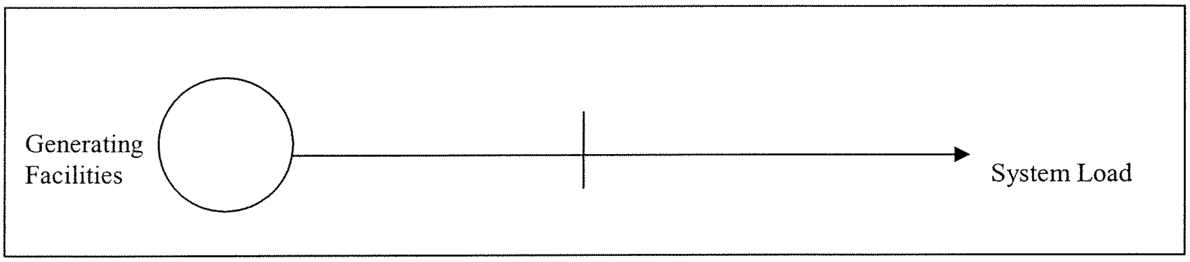
Historically, the LOLE is the most widely used index. It was first used in Canada by Ontario Hydro in 1964. The LOLE indicates the number of hours in a year when the available generating capacity cannot meet the entire demand. It is limited to indicating the fact that the installed capacity is inadequate. The LOEE index is less used, and is oriented to calculating the expected unserved energy due to generating capacity deficiencies.

THE SNARE-YELLOWKNIFE SYSTEM

Dr. Billinton, with input from NTPC and the Working Group, developed computer software to evaluate the generating capacity adequacy of the Snare-Yellowknife system based on conventional probabilistic techniques. The adequacy of the generation facilities to serve the load is expressed in terms of the LOLE in hours/year and the LOEE in MW.h/year. Both parameters are planning indices which do not include operating concerns such as spinning reserves.

The conventional approach to generating capacity assessment in a system with a tightly networked bulk transmission system is to simply compare the probability that the generation output will be in excess of the load expected throughout the year, and calculate an index of how many hours and how much load is expected to not be served due to generation plant availability. This model is represented in Figure 1 and is referred to as the ***SYSREP Generation-only*** approach.

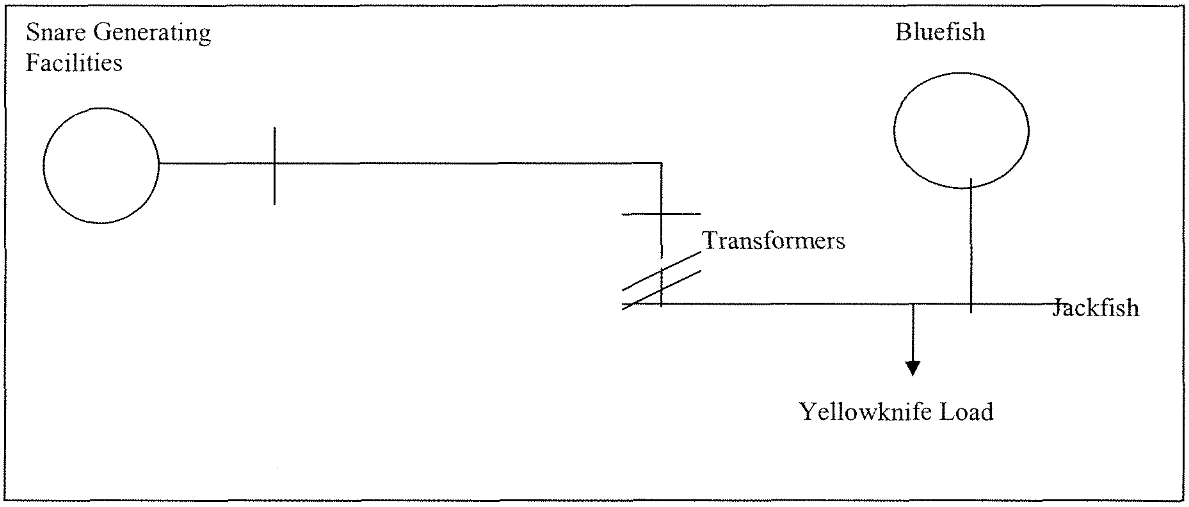
Figure 1 – Basic Generation Capacity Model



Under the generation-only approach, the location of the generation and loads are not consequential, since the transmission and transformation are ignored (assumed to be sufficiently redundant and reliable that they are not considered in the generation model). This is similar to the types of modelling done on the systems in southern Canada

However, the Snare Yellowknife system has a significant portion of its generating capacity located on the Snare River approximately 150 km from its main load center in Yellowknife, and is susceptible to outages due to reliance on the single transmission line. In order to address this system configuration, the SYSREP model for the Snare-Yellowknife system can combine the reliability model for the Snare generating facilities with a Transmission and Transformation model to create an equivalent model at the Yellowknife load point. This model is then combined with the Jackfish and Bluefish generation facilities to create a single generation model at the Yellowknife load point. The single generation model and the Yellowknife load models are then combined. This approach is shown in Figure 2 and is referred to as the ***SYSREP Generation and Transmission/Transformation*** approach.

Figure 2 – Basic Snare/Yellowknife Generation and Transmission/Transformation Capacity Model



The output of the SYSREP model indicates that the Generation-only LOLE is very low (0.145 hours/year in 2004/05 before the mines close, much lower afterwards), and indicate that most of the LOLE for Yellowknife arises due to outages of the L199 transmission line.

SNARE-YELLOWKNIFE PROBABILISTIC PLANNING MODEL

The probabilistic capacity planning criteria for the Snare Yellowknife Zone developed under the guidance of Dr. Billinton is as follows.

The generating units that will be taken into account for the purpose of planning for the Snare Yellowknife Zone are listed in Table 1. The planning capacity of each of the units, the nameplate rating, and the forced outage rates (FOR) are detailed in Table 1 below.

Table 1: Generation Plant

Generation Unit	Planning Capacity Rating (kW)	Nameplate Capacity (kW)	Planning Forced Outage Rate (FOR)
Snare Rapids #1	7,400	8,000	1.4%
Snare Rapids #2	0	500	1.4%
Snare Falls	7,500	7,500	1.4%
Snare Cascades	3,800	4,300	1.4%
Snare Forks #1	2,500	4,500	1.4%
Snare Forks #2	2,500	4,500	1.4%
Bluefish #1	3,300	3,600	1.4%
Bluefish #2	3,300	3,600	1.4%
Frank's Channel	0	500	12.9%

Frank's Channel	0	700	12.9%
KV16	5,180	5,180	12.9%
KV16	5,180	5,180	12.9%
EMD (1)	2,865	2,865	12.9%
EMD (2)	2,865	2,865	12.9%
EMD (3)	2,500	2,500	12.9%
EMD (4)	2,500	2,500	12.9%
3612 (1)	3,300	3,300	12.9%
3612 (2)	3,300	3,300	12.9%
Ruston	2,000 (removed for 2005/06)	2,000	12.9%

The reason for the variation between nameplate ratings and planning capacity ratings for hydro units are largely due to the fact that it is winter conditions that are relevant for the purposes of planning NWT generation (as that is when the load is at its peak) and winter hydro capacities do not necessarily reflect the same potential output as nameplate.

- ***Snare Rapids:*** The current generating unit is restricted by winter water flows to a level less than the full nameplate rating. The 500 kW unit does not operate at winter water flow levels. This is further discussed in YK&HR-NTPC-18(c) from the Corporation's 2001/03 Phase I GRA.
- ***Snare Cascades:*** The nameplate rating was developed based on peak capacity evaluation. When operated in parallel with Snare Falls, the station can produce a reliable 3800 kW. This was explained in detail in NUL-NTPC-7 and NUL-NTPC-63 from the Corporation's 1995/98 Phase I GRA.
- ***Snare Forks:*** The two units are each capable of putting out the nameplate rating individually. However, when operated in combination, the units can only achieve 5000 kW at winter water flows.
- ***Bluefish:*** The two units are each capable of putting out the nameplate rating individually. However, when operated in combination, the units can only achieve 6600 kW at winter water flows due to penstock and head restrictions.
- ***Frank's Channel:*** The two units at Frank's Channel are not assumed to be able to support the Yellowknife load point under normal supply constraints (typically at high load winter hours) – as either a) the units are required for servicing the Rae/Edzo load, which leaves very little if any surplus to support the grid, or b) the units are isolated from the Yellowknife load point as the transmission system is down. In either case, the Yellowknife load point should not be assumed to benefit from the Frank Channel units under planning assumptions. Likewise, the SYSREP model does not include the Rae/Edzo loads, as the Yellowknife supply point does not supply these loads (as they would likewise be isolated by a winter transmission interruption, or be otherwise serviced by the Frank's Channel diesels). This approach to modelling Rae/Edzo is consistent with the typical

approach used elsewhere for similar "interruptible loads"; that is if a customer's load can be interrupted, either by the customer reducing load under some form of curtailable rate or by starting up their own generation to effectively remove the load from the system, that load is not modelled as a required firm load for the purposes of calculating LOLEs.

The Corporation proposes to continually review the Snare-Yellowknife generation units as events unfold, such as the upgrade of the Snare Rapids hydro plant, with a view to adjusting the SYSREP model inputs as required.

Under the SYSREP Generation and Transmission/Transformation approach, the Snare Yellowknife Transmission Line and certain key transformers located within the Jackfish Station Site are taken into account, as detailed in Table 2. The forced outage rate for the transmission line and each of the transformers is also detailed in Table 2.

Table 2: Transmission Plant

Transmission	Planning Unavailability (per Canadian Electricity Association)
Snare-Yellowknife	0.12%
Bluefish	0.21%
Transformers	0.22325%

COMPARISON TO SOUTHERN UTILITY TARGETS

For reference, NTPC has asked Dr. Billinton to develop Table 3 below indicating the LOLE targets for a number of southern Canadian jurisdictions. These risk indices in other places are somewhat different than the LOLE planning target NTPC proposes for two reasons (they reflect the reliability at the high voltage delivery level, not the low voltage side of transformation, and they are planning maximums; that is, the system is designed so that they are not exceeded), however they do provide useful information in assessing NTPC proposed LOLE planning target.

Table 3: Comparison of Risk Indices
(data compiled by Dr. Billinton)

System	LOLE* (Hours/Year)
Newfoundland Hydro & Labrador Hydro	2.0
Alberta Electric Interconnected System (prior to deregulation)	2.0
BC Hydro & Power Authority	1.0
Manitoba Hydro – single system	1.0
- connected system	0.03
Hydro Quebec	2.4
Nova Scotia Power Corporation	1.0

* The LOLE indices in Hours/Year were obtained by multiplying the stated Canadian Electrical Association (CEA) index in Days/Year by a factor of 10. This is a reasonable practical approximation. The actual factor will be different for each system and is dependent on the daily load shape, capacity reserve, generating unit sizes and forced outage rates in each system.

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 14-2004 **November 29, 2004**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by the Northwest Territories Power Corporation for approval of Capacity/Reliability Planning Criteria for generation.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	John E. Hill	Chairman
	Joe Acorn	Member
	Gabrielle Decorby	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

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APPEARANCES

Stephen Lee	Counsel for Northwest Territories Power Corporation
Tom Marriott	Counsel for The City of Yellowknife

WITNESSES

For Northwest Territories Power Corporation

Judith Goucher	Director and Chief Finance Officer
Dan Grabke	Senior Policy Advisor, Corporate Affairs
Al Dube	Director, Engineering and Chief Engineer
Patrick Bowman	Consultant
Roy Billinton	Consultant

For the City of Yellowknife

Robert Bruggmen	Consultant
William Marcus	Consultant

1. BACKGROUND

In its Phase I General Rate Application for 2001/02 and 2002/03 test years, filed on May 9, 2001, the Northwest Territories Power Corporation ("**NWTPC, the Corporation**") requested, among other matters, that the Board approve NWTPC's Required Firm Capacity Planning Criteria for the isolated diesel Communities, dual fuel generation communities and the Snare Yellowknife Zone.

As a result of a negotiated settlement agreement, dated November 20, 2001, NWTPC withdrew the proposed capacity planning criteria for the Snare Yellowknife zone. NWTPC and interested parties agreed to diligently and in good faith pursue further discussions with a view to resolving their differences by October 1, 2002. The parties agreed, in the event that an agreement among all interested parties was not reached by such date, that the Corporation could make application to the Board to have the Board resolve the issue.

In Decision 1-2002, the Board accepted the negotiated settlement and consequently the proposal to withdraw the capacity planning criteria for the Snare Yellowknife zone. Further, in the same Decision, the Board directed NWTPC to examine the capacity planning criteria proposed for dual generation source communities in light of the circumstances of each community.

The discussions among interested parties that followed the negotiated settlement did not result in consensus with respect to capacity planning criteria for the Snare Yellowknife zone. Following this, NWTPC filed an application for approval of Capacity/Reliability Planning Criteria for generation for all communities served by NWTPC.

2. APPLICATION

By letter dated April 21, 2004, NWTPC requested an order or orders of the Board to approve the following required firm capacity planning criteria for all NWTPC communities:

1. **Isolated Diesel Systems:** ensure that 110% of the forecast peak load can be met with the largest single unit out of service, subject to engineering judgement.
2. **Dual Fuel Communities:** ensure that 105% of the forecast peak load can be met with the primary supply out of service, subject to engineering judgement. The primary supply for the dual fuel communities is as follows:
    a. **Fort Smith and Fort Resolution:** The Taltson hydro supply
    b. **Norman Wells:** The purchased power supply
    c. **Inuvik:** The gas pipeline supply
    d. **Rae/Edzo and Yellowknife:** The Snare hydro supply (see Snare-Yellowknife zone below)
3. **Snare/Yellowknife Zone:** achieve a long-term target Loss of Load Expectation (LOLE) of 2 hours/year (using the SYSREP Generation and Transmission/Transformation approach) at the Yellowknife load point. The System Reliability Evaluation Program (SYSREP) is a probabilistic model used to assess the reliability of resource adequacy at the Yellowknife load point considering the Snare generating facilities, the L199 Transmission and Transformation facilities connecting the Snare generating facilities to the Yellowknife load point, the Jackfish diesel generating facilities and the Bluefish hydro generation facilities. The SYSREP model is described in Attachment B of NWTPC's application. Also, for each load point the following specific criteria:

a. **Yellowknife minimum diesel:** require the supply available to be able to carry 105% of the forecast peak loads at the Yellowknife load point (exclusive of the mines) with all Jackfish and Bluefish units in service (i.e., with the Snare hydro transmission supply out of service) subject to engineering judgement.
b. **Rae/Edzo minimum diesel:** ensure that 105% of the forecast peak load can be met with the Snare hydro transmission supply out of service, subject to engineering judgement.

NWTPC provided copies of the Application to all interested parties in the 2001/03 General Rate Application ("**GRA**").

Pursuant to the provisions of section 13.(1) of its Rules of Practice and Procedure, the Board, by letter dated July 20, 2004 directed NWTPC to publish notice of the public hearing of the Application in newspapers that circulated in the Northwest Territories.

Intervener evidence was filed on behalf of the City of Yellowknife ("**the City**") by letter dated August 13, 2004.

A public hearing was held in the City of Yellowknife on September 1st and 2nd, 2004. During the course of the hearing, members of the public were invited to participate in the proceeding. Written argument and written reply argument were filed on September 20, 2004 and September 27, 2004, respectively.

3. CONSIDERATION OF THE APPLICATION

3.1 Isolated Diesel Systems

NWTPC proposed that the existing deterministic planning criteria for single generation source communities be continued, subject to engineering judgement. Under these criteria the installed capacity is required to be adequate to meet 110% of forecast peak load with the largest single unit out of service. Examples of engineering judgement were set out at page 2 of 17 of the Application as follows:

- "engine and generator ratings and related information provided by the manufacturer;
- engine and generator age, including considerations of both operating hours and years in service;
- engine and generator condition, including consideration of operating and maintenance history, as well as manufacturers original specifications;
- genset control system condition, including consideration of type of governor and whether manual or automatic control;
- genset auxiliaries condition, including condition of the jacket-water cooling, combustion air handling and fuel delivery systems;
- shape of the load duration curve and other relevant load data and information;
- experience of onsite operators and availability of maintenance personnel and backup equipment;
- the potential availability of portable and third party generation;
- the potential availability of customers who can interrupt part of their load if required; and,
- the sizing of the power plant to be installed will likewise require judgement of similar factors to those noted above, as well as such factors as load growth expected, economy of operation (fuel efficiency, etc.) and ease of maintenance;
- other relevant data and information relating to the particular circumstances of the plant and community in question" (Ex 2, p.2)

NWTPC stated a 10% safety margin is reasonable to account for load forecasting error given the impact individual customers can have on a community's total load.

NWTPC indicated the units comprising the installed capacity are configured to maximize efficiency and reduce fuel costs so that the largest unit is typically sized to serve the average load of the community. As a result of these efficiency considerations as well as availability of units typically in standard sizes and the configuration of existing units, installed capacity may sometimes significantly exceed peak load.

NWTPC indicated short term supply and demand side alternatives will continue to be considerations of engineering judgement and may be considered when contemplating the timing of additional capacity installations. In this regard NWTPC stated:

> "the Corporation intends on cataloging all local generation and interruptible loads in the communities it serves as part of an emergency response plan. It is currently anticipated that this work will be done over the course of the next year." (PUB NTPC-3)

The Board notes NWTPC's proposal is to continue the existing capacity planning criteria for isolated communities. From the evidence in these proceedings, the Board sees no reason to change the existing capacity planning criteria for isolated diesel communities. Accordingly the Board will approve the proposed criteria for isolated communities. The application of these criteria and the use of engineering judgement will continue to be tested as and when NWTPC brings forward applications for additions to generating capacity in the context of a GRA or a project permit.

The Board is of the view that the cataloging of all local generation and interruptible loads in the isolated communities the Corporation serves would assist in the application of the planning criteria and the exercise of engineering judgement. Accordingly, Board directs NWTPC to complete the cataloging of all local generation and interruptible loads in the isolated communities it serves as part of an emergency response plan and file a copy of the report with the Board at the earlier of the next GRA or at the time of the next project permit application for generation capacity additions for the applicable communities.

3.2 Dual Generation Source Communities

NWTPC proposed that the existing, interim, deterministic planning criteria for dual generation source communities be continued, subject to engineering judgement. Under these criteria the installed capacity is required to be adequate to meet 105% of forecast peak load with the primary supply source out of service. The dual generation source communities considered in this section and their respective primary sources of supply are as follows:

- Fort Smith and Fort Resolution: Taltson hydro supply
- Norman Wells: Purchased power supply from Imperial Oil
- Inuvik: Gas pipeline supply

The dual generation source community of Rae Edzo is part of the Snare Yellowknife zone and will be considered as part of the discussion of that zone.

NWTPC stated the reduced safety margin of 5% proposed for dual generation source communities (compared with 10% for isolated communities) gives recognition to that fact such communities tend to be larger and therefore easier to forecast, have a diversity of supply (primary vs. diesel) and have more reliable primary supply. The dual generation source communities are discussed separately below.

Fort Smith/Fort Resolution:

For the dual generation source communities of Fort Smith and Fort Resolution the primary source of supply is the Taltson hydro system. In support of its proposal for Ft Smith/Ft Resolution, NWTPC stated:

> “As the Taltson hydro only generates notable power out of the single generator, outages for servicing (typically in summer) are required to be met by potentially extended use of diesel. As a result, these plants are both required for winter backup and for summer maintenance shutdowns.” (Ex 2, p. 4)

Norman Wells:

For the town of Norman Wells, the primary source of supply is purchased power from Imperial Oil. As justification for maintaining diesel generation to meet 105% of the peak load requirements in addition to the primary source. NWTPC stated:

> “The town of Norman Wells is primarily supplied by purchased power from Imperial Oil. Although supply from Imperial is very reliable and has its own internal redundancies, the Corporation cannot control or dispatch the generation. In addition, there have been discussions regarding the likely length of time the Corporation can expect to be served by Imperial, and although there have been no decisions made, the supply is not indefinite.

> As a result, the Corporation's diesel plant must be available for purchased power supply unavailability." (Ex 2, p. 4)

Inuvik:

For the town of Inuvik, the primary source is considered to be the natural gas pipeline supplying gas generation in Inuvik. Natural gas is supplied by means of a 50 Km length pipeline transporting gas from two gas wells. NWTPC states:

> "Since there are two gas wells on this system, there is some redundancy which allows for the maintenance and/or loss of supply from one well while still maintaining production from the second. Although the pipeline is a non-redundant system, it is a relatively short line that can be quickly repaired in the event of a breach." (PUB NTPC-5 (b))

Under examination in the hearing, NWTPC expressed the view there has been some level of debate as to whether the largest single contingency needed to be the gas pipeline or whether it could have been one of the gas units:

> "the criteria for Inuvik may be one (1) of the -- the trickier ones that -- that's been developed and put in a package here and it's fair to say that there was some level of debate as to whether the largest unit needed to be the pipeline or whether it could have been one (1) of the gas units which I think is the point that you're getting at.
>
> Certainly at this point with the -- the amount of experience that the Corporation has with the gas, the end conclusion was that it needed to consider the gas pipeline as the largest possible failure similar to the other criteria though -- here it doesn't mean that -- that in future with more experience and -- and more information from the pipeline operator or -- or a different configuration of pipelines." (Tr. Vol. I, p. 150, *l*. 18 – p. 151, *l*. 6)

In Decision 1-2002, the Board directed NWTPC as follows:

> "The Board considers differences in reliability levels of the primary source in each dual generation source community should be recognized to the extent they are material. Further, the reliability levels at dual generation source communities ought to be comparable to other communities served by NWTPC, unless there is valid reason to deviate from this standard. The Board therefore directs NWTPC to review the planning criteria for each dual fuel community in light of its particular circumstances and provide its findings together with a proposed set of planning criteria for approval at the time the planning criteria for the Snare Yellowknife zone are filed for approval." (Decision1-2002, p. 19-20)

In response to this direction, NWTPC stated it does not recommend adjusting any dual fuel community's safety margin to reflect potential differences in primary supply reliability, especially if that would result in reducing the safety margin to the point where the Corporation was not able to meet the peak load when primary supply failed. (NWTPC Argument, p. 7)

The Board notes NWTPC's proposal is to continue the capacity planning criteria for dual generation source communities approved on an interim basis in Decision 1-2002. From the evidence in these proceedings, the Board sees no reason to change the capacity planning criteria that were approved on an interim basis in Decision 1-2002 for the communities of Fort Smith/Fort Resolution and Norman Wells. Accordingly, the Board will approve the proposed criteria for the communities of Fort Smith/Fort Resolution and Norman Wells. The application of these criteria and the use of engineering judgement will continue to be tested as and when NWTPC brings forward applications for additions to generating capacity in the context of a GRA or a project permit.

The Board is of the view that the cataloging of all local generation and interruptible loads in the dual generation source communities the Corporation serves would assist in the application of the planning criteria and the exercise of engineering judgement. Accordingly, Board directs NWTPC to complete the cataloging of all local generation and interruptible loads in the dual generation source communities it serves as part of an emergency response plan and file a copy of the report with the Board the earlier of the next GRA or at the time of the next project permit application for generation capacity additions for the applicable communities.

With respect to Inuvik, the Board notes that although there has been some debate as to whether the gas pipeline needs to be the largest single contingency, the Corporation takes the view the proposed criteria are appropriate having regard to experience to date. The gas pipeline, although it is considered a non redundant primary source, is a relatively short line and can be quickly repaired in the event of a breach. The Board notes Inuvik is a growing community and a review of generation requirements may be necessary within the next five years. (Tr. Vol. I, p. 151 - 152)

The Board infers from NWTPC's evidence that although there may be outages on the gas line the resulting outages in electrical generation may not necessarily be extended in duration. Further, since inception, there has been one outage in electrical generation related to gas supply due to difficulties experienced in the gas supply metering station. Given the apparent high degree of reliability of the gas pipeline, the Board is not persuaded by NWTPC's evidence that it is appropriate to carry diesel standby capacity to meet 105% of peak load in the event of the gas line failure and the consequent failure of the gas units. The Board considers further work needs to be carried out to assess the appropriateness of treating the gas pipeline as the largest single contingency for Inuvik considering the risk of generation loss due to pipeline supply failure.

Accordingly, the Board directs NWTPC to file a study addressing the question of what is the appropriate largest contingency for Inuvik. The study should be filed at the time of the next GRA or project permit application respecting Inuvik or within one year from the date of this Decision, whichever is earliest.

3.3 Snare Yellowknife Zone

3.3.1 General

NWTPC proposed the following planning criteria for the Snare Yellowknife zone:

- A long-term target loss of load expectation ("LOLE") of 2 hours per year using the Snare-Yellowknife System Reliability Evaluation Program ("SYSREP") generation and transformation/transmission approach at the Yellowknife load point, subject to engineering judgement.
- *Yellowknife load point minimum diesel*: 105% of the Yellowknife load point forecast, without Con and Giant mine load, met with the primary supply out of service, where the primary supply is the Snare hydro (i.e. only Jackfish and Bluefish units in service), subject to engineering judgement.
- *Rae-Edzo load point minimum diesel*: 105% of the Rae-Edzo load point forecast met with the primary supply out of service, where the primary supply is the Snare hydro (i.e. only Frank's Channel units in service), subject to engineering *judgement*. (NWTPC Argument, p. 2)

NWTPC stated the minimum diesel criteria for the Yellowknife load point and the Rae Edzo load point were designed to serve the respective loads with the primary source of supply out of service. The primary source in this instance is the

L199 transmission system connecting the Snare hydro system to the two load points. Failure of the primary source is also considered the largest single contingency. Planning the system to meet load with the largest single contingency out of service has been referred to as the N-1 criterion, a practice commonly used by utilities for planning purposes.

The City did not oppose the probabilistic 2 hours per year LOLE criterion for assessing capacity requirements for the Snare Yellowknife zone. However, the City disagreed with a number of input parameters that NWTPC proposed be used to model the system in order to assess capacity requirements.

The City also disagreed with NWTPC's treatment of the L 199 line as the largest single contingency under the N-1 criterion. In this regard the City stated:

> "The City submits that "N-1" planning, while common in the utility industry, is only reasonable if it is cost-effective. We should not be planning to spend millions of dollars to obtain relatively small increments of reliability." (City of Yellowknife Argument, p.12)

The City argued that the reliability criteria and the application of those criteria should strike a balance between reliability and cost:

> "It appears to the City that the NTPC is attempting to obtain approval for its reliability criteria for the Snare-Yellowknife system in the abstract, without looking at real world cost impacts of its proposals. The City believes that any Board decisions should not be simply based on abstract principles but should consider the likely impacts of its decision on both reliability and cost. Therefore, the City attempted, through its evidence, to give the Board its best estimates of the reliability and cost implications of the NTPC's reliability criteria and SYSREP parameters relative to alternatives that the City believes would be more reasonable." (City of Yellowknife Argument, p. 2)

NWTPC stated:

> "The Corporation recognizes that the cost of a specific reliability solution must be balanced against the somewhat competing objective of maintaining the high levels of service expected by customers. In the present application the task at hand is to determine appropriate criteria. How the criteria will be applied, how much alternative reliability solutions will cost and is the cost justifiable in light of the incremental reliability achieved are all questions to be answered when a specific capacity addition is being reviewed." (NWTPC Reply, p. 1)

It is the Board's view that the purpose of these proceedings is to not only determine the appropriate capacity planning criteria but also to provide guidance to the utility in regard to the application of those criteria.

A consideration of the issues raised during the proceeding follows:

3.3.2 Input Assumptions for LOLE Model

L199 Transmission Line and Transformer Reliability

NWTPC proposed that for purposes of modeling, the transmission and transformer unavailability rates based on national averages derived from a CEA-ERIS data base should be used. NWTPC indicated that the Corporation's transmission outage data is comparable to CEA-ERIS data in the frequency of outages but the average outage duration is almost three times better. NWTPC considered the reason why the outage duration is better is a matter of luck and this level of performance may not necessarily be the case in future. (Tr. Vol. I, p. 218)

The City recommended that for modeling purposes, the transmission and transformer unavailability rates should reflect the Corporation's 13 year to date actual experience. The City submitted there are reasons why the performance of the Corporation's transmission line performance is better than the CEA-ERIS data. These reasons include the following:

- NWTPC's line is relatively new when compared to an average of all transmission lines in the CEA-ERIS data
- Although the terrain traversed by NWTPC's transmission line experiences severe climatic conditions it does not have tornados, severe ice storms and wind conditions observed in the south
- The role of vegetation in causing outages is much more limited for NWTPC than for southern Canada since only small portions of the L199 traverse terrain with high vegetation
- NWTPC's proactive maintenance of the L199 line because of the importance to the system

NWTPC submitted the fact that the line is new may explain its relatively good performance in the past. Further, there is no evidence to assess the impact of weather, vegetation and maintenance practices of the utilities on the CEA-ERIS data set. The L199 line specific outage data, which the City proposes, is based on a single line whereas the CEA-ERIS data proposed by NWTPC reflects the diversity of experience with many transmission lines in a variety of locations and conditions.

Given the different factors the NWTPC and the City considered are important in assessing the future reliability of the L199 transmission system, NWTPC was examined on the appropriateness of an approach using melded data from the L199 transmission system's historical outage statistics as well as the CEA-ERIS statistics:

> " MR. JOE ACORN: I had a question about the transmission line from Snare down to Yellowknife. It just seems like there's no credit being given to that line for its impressive reliability over the last five (5) -- ten (10) years.
>
> Now, has there been any attempt or consideration by NTPC to melding the actual data versus CEA's data and perhaps increasing it from where -- from the actual data to CA's (sic) data at the end of the -- of the line's lifetime so that you're gradually moving it up towards what you expect, that way, at least giving some credit to the line for its performance over the last five (5), ten (10) years.
>
> MR. AL DUBE: I guess I have some difficulty in just melding them, as you suggest, unless there's some validity to it, to one (1) data or the other. We believe there is a lot of validity to the CEA data because there is a large sample.
>
> Certainly we give credit to the line and we hope to heck it continues but we don't expect it to. It will only take a couple of overnight outages or thirty-six (36) hour outages to put it right back up there and you're -- so, you're looking at a moving target, I guess. I'm not sure -- sure how valid it would be to use that melding as you say, or -- or an adjustment of one (1) or the other.
>
> MR. JOE ACORN: The followup then would be, I've heard just talk about why you want to use the CEA versus this -- the actual data but have you actually done the research to determine why this line has performed as well as it has compared to the -- the CEA analysis?
>
> MR. AL DUBE: I think we're -- we consider that we've been lucky. Things have happened at the right time. A good part of the line is only five (5) years old so it's not reflected." (Tr. Vol.I; p.217, *l*.11 – p. 218, *l*.21)

Having weighed the evidence, the Board considers that a 50:50 weighting of the L199 transmission system historical outage data and CEA-ERIS data would provide a reasonable balance between all of the factors affecting reliability of the

L199 Transmission system referred to by NWTPC as well as the City. Accordingly, the Board approves the use of transmission forced outage rates based on 50:50 weighting of the L199 transmission system historical outage data and CEA-ERIS data for the L 199 transmission system for purposes of the probabilistic LOLE modeling of the Snare Yellowknife system, for system planning purposes.

<u>Hydro Capacity</u>

NWTPC proposed to use hydro unit capacities based on average winter flow conditions. The City, on the other hand, recommended hydro unit nameplate capacities be used for modeling purposes to reflect capacity that is available for short periods of time to meet peaking requirements.

The City recommended an approach to dispatch that it believed would enable the Corporation to count on nameplate capacity for short term peaks:

> "In order to meet short term peaks or forced outages, it is submitted that NTPC should dispatch its hydro and diesel units progressively in the following order:
>
> i) Snare Forks up to 9,000 kW
> ii) Snare Cascades up to 4,300 kW
> iii) Rae-Edzo Diesel up to 1,200 kW
> iv) Snare Rapids #2 up to 500 kW
> v) Diesel Overload Capacity up to 1,500 kW
>
> The City considers that this dispatch order to meet relatively short term system shortfalls, will enable all of these resources to be made available. Further, items iii), iv) and v) can be interchanged or utilized for varying periods depending on the duration of the shortfall or operator availability to start the unit." (City of Yellowknife Argument, p. 21-22)

NWTPC, disagreed with the City, stating short term peaking capacity of the Snare hydro units should not be used for system planning purposes without regard to seasonal variations imposed by the hydrological conditions.

> "It is neither practically appropriate nor theoretically correct to incorporate emergency operating capacity of existing facilities into a generation adequacy planning model. For example, if the Corporation were to plan its Snare hydro unit capacities based on their short term peaking capability, as has been proposed by the City, customers would be forced to gamble that hydro peaking capacity is always available when in reality no one knows when or how often in the future such capacity can be called upon." (NWTPC Reply, p. 2)

The Board notes the City's evidence that while hydro units are capable of generating up to their nameplate ratings for relatively short periods during winter time they cannot do so for extended periods of time for energy purposes due to water flow limitations. The issue here is whether generation at the nameplate capacities of the Snare hydro units can be counted on for limited periods of time during winter and if so what would be the contribution of those units to the load carrying capability of the system.

The City estimates the impact of including 4.9 MW of additional hydro capacity is about 0.1 MW with NWTPC's transmission forced outage rates and about 2.3 MW with the lower transmission forced outage rates recommended by the City. (Ex. 5, p.18) The Board notes neither of these estimates reflects the limitations imposed by seasonal water flows.

Dr. Billington explained it would be difficult to reflect the limited capability of hydro units to generate up to their nameplate ratings for relatively short periods during winter in the LOLE model. (Tr. Vol II, p. 29) Given the modeling limitations, and the relatively minor impact of inclusion or exclusion of short term hydro capacity on the overall decision whether to add new capacity under the proposed N-1 criterion discussed later in this Decision, the Board will not require NWTPC to include hydro units at their nameplate capacities in the probabilistic LOLE model for capacity planning purposes. The Board approves the use of average winter water flow and reservoir levels for purposes of determining the hydro capacity to be included in the LOLE model.

Diesel Overload Capacity

NWTPC proposed the diesel units be modeled using nameplate maximum continuous ratings ("**MCR**"). In its evidence, the City identified an additional 3500 kW capacity above MCR (overload capacity) that could be relied on for peaking or emergency standby purposes. The City recommended that 1500 MW of the diesel overload capacity should conservatively be reflected in the model. In this regard the City stated:

> "The four days of highest peak load in 2003/04 were analyzed to assess how much overload capability should be conservatively relied upon to meet system peaks. Typically, the hours outside these peak periods were more than 1,500 kW below the peak load. If included for modeling purposes, the City would treat overload capacity as two units with a higher forced outage rate of 25% to reflect both limits on hours of use and other potential technical limits on availability." (City of Yellowknife Argument, p. 22)

NWTPC stated diesel overload capacity is emergency capacity and should therefore not be modeled at all.

The Board notes Dr. Billington's evidence as follows:

> "The conventional approach in capacity planning is to use the maximum continuous rating (MCR) as the basic capacity designation for a generating unit. The MCR value is sometimes seasonally de-rated to recognize ambient temperature or hydrological conditions. An overload rating is usually used in connection with operating reserve assessment in regard to the ability of a unit to respond to a sudden demand caused by large motor loads, faults or transient conditions. The use of overload capacity is considered as an emergency operating procedure and applied in security assessments of spinning or operating reserves. A key issue in operating reserve assessment is the delay time associated with starting, synchronizing and loading additional generating units given a sudden generating unit failure. Overload capability is sometimes used for limited periods to provide this delay time. My understanding is that the purpose of this proceeding does not involve consideration of operating criteria." (Ex. 7, Roy Billington Rebuttal, p. 9)

The Board accepts Dr. Billington's expert evidence that the conventional approach to capacity planning is to use the MCR of a generating unit. Accordingly, the Board accepts NWTPC's proposal that MCR of diesel units be used for modeling of the system for capacity planning purposes. The Board considers overload capacity to be a component of operating reserves.

<u>Load Shape Data</u>

For modeling purposes NWTPC used the highest 15 minute load within each hour to compute load shape. The City recommended NWTPC should be directed to use all available data, namely the 35040 fifteen minute data points in a given year to compute load shape. The City noted use of the highest 15 minute load within each hour would cause the model to give an incorrect estimate of loss of energy expectation.

NWTPC indicated it is willing to investigate the expense required to implement the City's 15 minute peak proposal.

The Board directs NWTPC to address the benefits of using each 15 minute peak for modeling purposes as well as the costs of implementing this approach at the time of the next GRA.

<u>Rae Edzo</u>

The City recommended the generation at Frank's channel, serving the Rae Edzo load point should be considered as part of the integrated Snare Yellowknife system for future LOLE modeling purposes. The City submitted inclusion of the Rae Edzo loads and resources in the model will improve the accuracy of future probabilistic runs, as well as reflecting the operations of the system because Rae Edzo diesel operation can affect Yellowknife reliability when the transmission line is in service.

NWTPC stated inclusion of Frank's channel generation in the model would not materially impact the LOLE results. NWTPC stated:

> "There is only one SYSREP model, and the entire configuration of the model is to consider the reliability of the system at Yellowknife. It can only consider a single load. If the system is modeled similar to Alberta, ignoring transmission and transformation constraints, then all grid generation and loads would be included, and the reliability measured at Yellowknife would be the same for Rae-Edzo or anywhere else on the grid.
>
> However, when transmission is added, it is no longer correct to include Rae-Edzo loads in the Yellowknife load point (since these loads do not exist at Yellowknife) and likewise it is not correct to include the Rae-Edzo generation (since this generation is not available to service Yellowknife load unless and until it has fully serviced Rae-Edzo load, and even then is only available if the transmission line is not out). In simple terms, the

> model ignores both Rae Edzo loads and generation to allow them to be treated consistently with the way an interruptible customer on the Alberta system is treated, who has their own emergency self generation. Such interruptible load need not be served at critical times, since they can be dropped off of the core grid supply, but they are not presumed to have any material excess generation that would aid in supply of the remainder of the grid." (PUB NTPC-11)

The Board considers NWTPC's proposed treatment of the Rae Edzo load to be reasonable given the transmission constraints. Accordingly, the Board accepts NWTPC's proposal to exclude Rae Edzo loads and resources from the probabilistic LOLE model for system planning purposes.

3.3.3 Minimum Diesel Criterion

Under the minimum diesel criterion for the Yellowknife load point, proposed by NWTPC, the combined capacities of diesel generation at Jackfish and Bluefish hydro generation are required to be adequate to meet 105% of peak City loads (excluding mine loads). Similarly, for the Rae Edzo load point the diesel generation at Frank's channel is required to be adequate to meet 105% of Rae Edzo loads.

The minimum diesel criterion is also referred to as the N-1 criterion where the loads at the Yellowknife load point and the Rae Edzo load point could be served with the loss of the largest single contingency. The largest single contingency for both load points was identified by NWTPC as the L199 transmission system. The deterministic minimum diesel criterion would override the probabilistic LOLE criterion if the former showed a requirement for capacity addition earlier than the latter.

The City stated it does not recommend a deterministic method because it places too much emphasis on a very narrow peak period. With respect to NWTPC's proposal to consider the L199 transmission system as the single largest contingency under the N-1 criterion, the City stated:

> "The City submits that "N-1" planning, while common in the utility industry, is only reasonable if it is cost-effective. We should not be planning to spend millions of dollars to obtain relatively small increments of reliability.
>
> Furthermore, if the Board wishes to consider "N-1" seriously, it should explore a series of other avenues to improve reliability besides simply building diesels in Yellowknife. These reliability improvements include rehabilitating the L190 line and making it readily operational under emergency conditions (holding a breaker open under normal operations but assuring that it is always ready for standby duty by bringing it up to standard and routinely testing it). Another means of improving transmission reliability that may be quite a bit less expensive than new diesels would be to install protective equipment to separate the Rae-Edzo tap from L199 if a fault is observed on that tap." (City of Yellowknife Argument, p. 12)

The City recommended if the Board were to consider the minimum diesel criterion for the Yellowknife load point that a lower level of requirement should be considered taking the following factors into account:

- The very low probability of transmission outage coincident with system peak -12 chances in 10000 according to NWTPC's use of CEA date and 5 chances in 10000 according to the City's use of NWTPC's historical transmission outage data
- The narrowness of the peak period -40 hours within 5% of peak
- Availability of other resources for emergency operational use-diesel overload in excess of the amount relied upon and possible capacity from the Ruston unit

- Ability to manage peak period outages in real time to reduce outages of firm customers through use of back up generation, possibly interruptible rates, and public appeals to conserve, and manage any outages that occur through a clearly defined policy of rotation

The City recommended that if a deterministic method is adopted the minimum diesel requirement should be no more than 100% of peak load for the Yellowknife load point.

NWTPC made the point the proposed minimum diesel criterion is no different than a similar criterion which existed in the past except the application of the criterion, was different:

> "What the City does not acknowledge is that even under the RIC criteria the "unwritten rule" that Jackfish diesel was sufficient to meet Yellowknife load (without the mines) with L-199 out was still being met.[1] In the past, the Corporation was able to meet that condition by interrupting the mine load and calling on Bluefish generation. Consequently, there is no basis for the City's statement that "…the conclusion one must draw is that [NTPC] has exposed the populace of the Northwest Territories to a tremendous level of risk up to now."[2] Today, because the mine load is diminishing, it cannot be relied upon as a generation planning resource for adequacy assessment purposes. The proposed Yellowknife minimum diesel criteria will ensure that Yellowknife load (without the mines) continues to be met with local generation (Jackfish and Bluefish) and L-199 out. There is no dramatic upward departure from the old RIC planning criteria, as alleged by the City. Further, it is notable that Northland Utilities applies a similar criteria to Hay River in that its local diesel generation must meet 110% of peak load.[3] In both cases, local backup generation is sufficient to meet the load plus a safety margin when the primary transmission supply is out of service." (NWTPC Reply, p. 3-4)

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1 Transcript, v. I, pp. 154, ln. 15 to p. 155, ln. 11.
2 City's Argument, p. 1.
3 PUB Decision 13-98, *Northland Utilities (NWT) Limited - Project Permit Application*, November 17, 1998.

The Board notes the N-1 planning criterion is an accepted practice used by utilities for system planning purposes. The Board notes the City did not object to the use of the N-1 criterion per se but rather had concerns with the designation of the L199 transmission line as the single largest contingency and the cost associated with the minimum diesel criterion as proposed by NWTPC. The Board notes the use of the N-1 criterion is consistent with prudent utility practice and approves the use of the N-1 criterion for system planning purposes on the Snare Yellowknife system.

The Board notes the evidence in this proceeding strongly suggests the single largest contingency under the N-1 criterion is a sustained outage on the L199 transmission system linking the Snare hydro units to the City of Yellowknife and the Hamlet of Rae Edzo. While there was evidence to suggest the reliability of the L199 system has been relatively good the evidence also indicates the potential for a sustained outage on this transmission system exists which could impact the loads being served at the Yellowknife and Rae Edzo load points under the present system configuration. This configuration may or may not change in the future. However, given the present configuration, the Board accepts and approves the treatment of the L199 transmission system as the single largest contingency under the N-1 criterion. Accordingly, the Board approves the minimum diesel criterion proposed by NWTPC for the Yellowknife load point and the Rae Edzo load point.

NWTPC recommends, to meet the minimum diesel criterion, generation sufficient to meet 105% of projected peak loads at each of the Yellowknife load point and the Rae Edzo load point be maintained. This is to meet loads in the event of a sustained outage on the L199 transmission system. The 105% reflects a safety factor for load forecast error.

The City recommends if the minimum diesel criterion were approved the 105% requirement be relaxed to 100% for the Yellowknife load point in view of the low probability of L199 transmission system outage, the narrowness of system peaks, the availability of overload capacity and spare capacity (Ruston Unit) from diesel units and the potential for demand side management.

The Board notes from NWTPC's evidence the coldest weather days in the City of Yellowknife give rise to sustained peak loads from about 9 AM through 10 PM with relatively little variation in demand. (Ex. 7, p. 10) The Board also notes demand side options, if any, for mitigating a sustained outage on the L199 system have not been examined or implemented at this time. The Board agrees with NWTPC short term emergency capacity from diesel units such as diesel overload and diesel spare capacity, should not be counted on for long term system planning purposes. For these reasons, the Board is not persuaded that the 105% minimum diesel requirement should be reduced. Accordingly, the Board approves the 105% minimum diesel requirement for the Yellowknife load point subject to engineering judgement.

The Board also approves the 105% minimum diesel requirement for the Rae Edzo load point, subject to engineering judgement.

The Board notes the significant gap of about 5 years advancement in capacity additions under the deterministic minimum diesel criterion compared with the probabilistic LOLE criterion for the Yellowknife load point. The Board also notes the City's concern regarding the cost of gaining the additional reliability by adopting NWTPC's criteria and parameters is extremely high, ranging from

$150,000 to $430,000 Per MWh of reduced loss of energy expectation or LOEE. The Board considers that the balancing of costs and reliability is an important part of engineering judgement when capacity additions are proposed by the Corporation.

The Board notes in particular, that the Corporation, while making reference to the possibility of sustained outages on the L199 transmission system, did not indicate the probable range in duration of such outages nor did it provide an estimate of the probable range in benefit to customers from avoiding such a sustained outage. The Board considers this type of cost benefit analysis should be part of the cost versus reliability assessment when a proposal is brought forward for capacity additions. The Board also notes neither the CEA statistics nor NWTPC's own outage statistics distinguish the different factors that may give rise to the L199 transmission outages during the different seasons. For example during summer months lightening strikes, forest fires and tornadoes may be dominant causes of outages whereas the factors giving rise to outages may be different in winter months. These differences must be considered in any analysis used to balance costs and reliability.

The Board expects NWTPC to support any proposals for capacity additions, pursuant to the planning criteria approved herein, with evidence on how factors of engineering judgment as set out in this section as well as other factors set out in the Corporation's application (Page 2) were considered, evaluated and applied.

3.3.4 Other Matters

<u>Other Transmission Reliability Issues</u>

The City submitted if the Board is considering an N-1 criterion, it should consider other avenues, such as rehabilitating L-190 or installing protective relays and breakers at the Smiley Lake tap to isolate the transmission line to Rae-Edzo. The City believed these options could be more cost effective compared with adding new diesel generation under the minimum diesel criterion.

With respect to rehabilitating the L-190 transmission line, the City stated:

> "Ultimately, if transmission reliability is of significant concern, the question of rehabilitating the L-190 line also comes into play. Under examination by the Board consultant, NTPC indicated that rehabilitating the L190 line was estimated to cost $6 million (far less than the $35 million cost of a new line).[4] Rehabilitating that second line would clearly provide more reliability than simply building more diesels at Jackfish, while also potentially providing a path for additional hydro construction if load growth were to warrant it in a number of years." (City of Yellowknife Argument, p. 16)

The City also suggested that installing protective relays and breakers at the Smiley Lake tap to isolate the transmission line to Rae-Edzo would improve reliability of the L199 line:

> "Finally, a review of the calculations provided by NTPC indicate that transmission reliability (as measured by the CEA) would be increased by approximately a third by installing protective relays and breakers to

[4] Tr. I-160.

> electrically separate the Rae-Edzo tap from the line from Snare to Yellowknife in the event of an outage on the line to Rae-Edzo . As noted by Dr. Billinton, "There's no circuit breaker at that particular point, and therefore, failure on that line would result in the entire line being removed from service." [5] Actual reliability would also improve to the extent that real-world outages that have occurred on the Rae-Edzo tap line would no longer result in the loss of L199. This would reduce the line kilometers from 210 km to about 145 km, thus preventing approximately 65 km of line from having a direct long-term impact on the City of Yellowknife (although a momentary outage might result before Rae-Edzo was separated). The City recommends that this option be investigated by NTPC as soon as possible, as a means of improving operational reliability for the City" (City of Yellowknife Argument, p. 16)

NWTPC acknowledged that if a second transmission line were put in place the treatment of the L199 line as the single largest contingency would need to be revisited:

> "If a second transmission line between the Snare hydro plants and Yellowknife were ever put in service, the Corporation agrees that it would be appropriate to revisit the Yellowknife minimum diesel criteria. The consideration at that time would be to identify the most critical element (i.e. N-1) on the newly configured system." (NWTPC Reply, p. 4)

NWTPC noted that installing a circuit breaker at Smiley Lake is relevant to the probability of a failure on L-199 for SYSREP modelling purposes. However, It would not change L-199's current status as the most critical element on the Snare-Yellowknife system under a N-1 criteria. (NWTPC Reply, p. 6)

The City estimated the gain in reliability from adopting the minimum diesel criterion for the Yellowknife load point is very high ranging from $150,000 to

[5] Tr. II-23

$430,000 per MWh of reduced loss of energy expectation. (City of Yellowknife Argument, p. 10)

Board Findings

The Board notes the economic argument advanced by the City and notes the high cost of reliability under NWTPC's minimum diesel proposal. The Board considers a different configuration of the system such as rehabilitation of the L190 transmission line may or may not open other possible ways of meeting the N-1 criterion at lower cost. The Board notes rehabilitating the L190 line may lead to a different element of the system being identified as the single largest contingency under the N-1 criterion. The Board is of the view that it is appropriate to investigate this option to determine if it might be a more cost effective alternative to the proposed treatment of the L199 transmission system as the single largest contingency. Accordingly, the Board directs NWTPC to investigate the feasibility, costs and benefits of rehabilitating the L190 transmission line and assess the impact thereof for system planning under the N-1 criterion and report its findings at the time of the next GRA.

The Board notes the City's recommendation that installing protective relays and breakers to electrically separate the Rae-Edzo tap from the line from Snare to Yellowknife in the event of an outage on the line to Rae-Edzo could improve reliability of the L199 transmission system. Given the critical nature of the L199 transmission system for the reliability of the Snare Yellowknife system, the Board is of the opinion that all feasible options for improving the reliability of the L199 system should be investigated. Accordingly, the Board directs NWTPC to report on the feasibility of installing protective relays and breakers to electrically separate the Rae-Edzo tap from the line from Snare to Yellowknife in the event of an outage on the line to Rae-Edzo, or vice versa, at the time of the next GRA.

Ruston and Caterpillar 3612 Diesel Units

NWTPC did not include in its LOLE model or minimum diesel calculations the 2000 kW nameplate capacity of the Ruston diesel unit at the Jackfish plant. After reviewing the relatively low reliability record of the Ruston unit, the City agreed the unit should not be counted as a resource for purposes of computing LOLE in a probabilistic analysis. However, the City believed the unit should not be decommissioned but instead efforts should be made to spend at least limited amounts of money to retain it in standby use in Yellowknife as an extra resource that might have value in emergencies. The City recommended NWTPC should report on the feasibility of retaining the Ruston unit in standby service at the next GRA.

The City questioned NWTPC with respect to two diesel units at Jackfish namely the Caterpillar 3612 units which NWTPC indicated cannot be expected to provide the prime and standby capacities as set out in their performance data. Each of these units has a nameplate capacity of 3300 KW. NWTPC indicated it has sought recourse from the manufacturers with respect to this matter. The City questioned NWTPC on why this problem, identified some 6 years ago has not been rectified. (Tr. Vol I, p. 83) The City recommended NWTPC should report on the steps being taken to bring these units into full operability at the next GRA.

With respect to the Ruston unit, NWTPC stated:

> “The City’s witnesses agree with NTPC that the Ruston unit does not represent reliable capacity, and should be excluded from SYSREP. In coming to their conclusion that the Ruston unit should be maintained despite it not being included in SYSREP as reliable plant, the City’s witnesses determine that the costs to maintain Ruston are $18/kW/year by

> using a 9 year average. However, for the last number of years this unit has been basically unavailable throughout the year due to mechanical problems. In other words, the historical 9 year average maintenance costs are not representative of the costs that would need to be incurred to maintain Ruston in any credible dispatchable condition going forward. It would not be prudent for NTPC to spend the amounts required to maintain this unit." (Ex. 7. p. 15 – 16)

The Board accepts NWTPC's evidence that it would not be cost effective to maintain the Ruston unit in order to provide back up capacity.

The Board agrees that the City's recommendations respecting the Caterpillar units will assist all parties from the point of view of application of engineering judgement when the next capacity addition is considered for the Snare Yellowknife load point. Accordingly, the Board accepts the City's recommendations and directs NWTPC to report on the steps being taken to bring the two Caterpillar units into full operability, at the next GRA.

<u>Outage Management Plan</u>

The City recommended NWTPC be required to file an outage management protocol within 6 months that would include information on:

a. Availability of backup generation on the NUL system
b. Availability of other interruptible loads if rates were adopted on the NUL system
c. Specific communication protocols between NUL and NTPC in the event of an outage.
d. Methods for making public appeals to conserve energy and estimating savings from such appeals.
e. Methods for rotating outages to manage any sustained outages. (City of Yellowknife Argument, p. 31-32)

In response, NWTPC stated the Corporation and Northland Utilities (Yellowknife) Limited ("**Northland**") hold regular coordination meetings. Based on Northland's input NWTPC is presently not aware of any interruptible load within Yellowknife. NWTPC stated it is its intention to catalog local generation and interruptible loads within communities it serves and will continue to work with Northland respecting Yellowknife. Since coordination with Northland is involved NWTPC proposed the more appropriate timeframe for dealing with these issues is Northland's next GRA.

The Board agrees with the City the development of a coordinated outage management protocol with Northland is a prudent objective to ensure adequate short term operating reserves are available in the event of system emergencies. Accordingly, the Board directs NWTPC to work with Northland and develop a coordination plan and associated protocols designed to mitigate short term emergencies. The plan should address among other matters the following:

- Availability and use of backup generation on the Northland system
- Availability and use of other interruptible loads if the necessary rate changes were adopted on the Northland system
- Specific communication protocols between Northland and NWTPC in the event of an outage.
- Methods for making public appeals to conserve energy and estimating savings from such appeals.
- A time table for plan implementation

NWTPC is directed to report to the Board, with copies to interested parties, on progress with respect to the plan on a quarterly basis, commencing with the first report on April 1, 2005.

The Board also considers it appropriate to investigate and catalogue demand and supply side options that may mitigate the risk of sustained outages resulting from the largest contingency on the Snare Yellowknife system, the L199 transmission system. One option recommended by the City is a protocol for managing sustained outages through rotating outages on the Northland system. NWTPC is directed to work with Northland and identify the number of megawatts of demand and supply side resources on the Northland system that can be relied on to mitigate the risk of sustained outages resulting from the largest contingency on the Snare Yellowknife system, namely the L199 transmission system. NWTPC should also address the extent to which the availability of these resources may impact the amount of required generation capacity under the minimum diesel criterion for the Yellowknife load point. NWTPC is directed provide a report to the Board on the availability and plan for deployment of resources designed to meet sustained outages on the Snare Yellowknife system at the time of the next GRA.

4. BOARD DIRECTIVE

1. The Board directs NWTPC to complete the cataloging of all local generation and interruptible loads in the dual generation source communities it serves as part of an emergency response plan and file a copy of the report with the Board the earlier of the next GRA or at the time of the next project permit application for generation capacity additions for the applicable communities.

2. The Board directs NWTPC to complete the cataloging of all local generation and interruptible loads in the isolated communities it serves as part of an emergency response plan and file a copy of the report with the Board at the earlier of the next GRA or at the time of the next project permit application for generation capacity additions for the applicable communities.

3. The Board directs NWTPC to address the appropriate largest contingency for Inuvik at the time of the next GRA or project permit application respecting Inuvik or within one year from the date of this Decision, whichever is earliest.

4. The Board directs NWTPC to address the benefits of using each 15 minute peak for modeling purposes as well as the costs of implementing this approach at the time of the next GRA.

5. The Board directs NWTPC to investigate the feasibility, costs and benefits of rehabilitating the L190 transmission line and assess the impact thereof for system planning under the N-1 criterion and report its findings at the time of the next GRA.

6. The Board directs NWTPC to report on the feasibility of installing protective relays and breakers to electrically separate the Rae-Edzo tap from the line from Snare to Yellowknife in the event of an outage on the line to Rae-Edzo, or vice versa, at the time of the next GRA.

7. The Board directs NWTPC to work with Northland and propose a coordination plan and associated protocols designed to mitigate short-term emergencies. The plan should address among other matters the following:

   - Availability and use of backup generation on the Northland system
   - Availability and use of other interruptible loads if the necessary rate changes were adopted on the Northland system
   - Specific communication protocols between Northland and NWTPC in the event of an outage.
   - Methods for making public appeals to conserve energy and estimating savings from such appeals.
   - A time table for plan implementation

   NWTPC is directed to report to the Board, with copies to interested parties, on progress with respect to the plan on a quarterly basis, commencing with the first report on April 1, 2005.

8. NWTPC is directed to work with Northland and identify the number of megawatts of demand and supply side resources on the Northland system that can be relied on to mitigate the risk of sustained outages resulting from the largest contingency on the Snare Yellowknife system, namely the L199 transmission system. NWTPC should also address the extent to which the availability of these resources may impact the amount of required generation capacity under the minimum diesel criterion for the Yellowknife load point. NWTPC is directed provide a report to the Board on the availability and plan for deployment of resources designed to meet sustained outages on the Snare Yellowknife system at the time of the next GRA.

5. BOARD ORDER

NOW THEREFORE, IT IS ORDERED THAT:

1. The Board approves the Northwest Territories Power Corporation's firm capacity planning criteria as follows:

   a) Isolated Diesel Systems

   110% of the forecast peak load met with the largest single unit out of service, subject to engineering judgement.

   b) Dual Generation Source Communities of Fort Smith, Fort Resolution and Norman Wells

   105% of the forecast peak met with the primary supply out of service, subject to engineering judgement, where the primary supply for each of the dual fuel communities is as follows:

   - Fort Smith and Fort Resolution: Taltson hydro supply;
   - Norman Wells: purchased power from Imperial Oil Resources N.W.T. Limited;

   c) Snare-Yellowknife Zone

   - A long-term target loss of load expectation ("LOLE") of 2 hours per year using the Snare-Yellowknife System Reliability Evaluation Program ("SYSREP") generation and transformation/transmission approach at the Yellowknife load point, subject to engineering judgement.

- Yellowknife load point minimum diesel: 105% of the Yellowknife load point forecast, without Con and Giant mine load, met with the primary supply out of service, where the primary supply is the Snare hydro (i.e. only Jackfish and Bluefish units in service), subject to engineering judgement.
- Rae-Edzo load point minimum diesel: 105% of the Rae-Edzo load point forecast met with the primary supply out of service, where the primary supply is the Snare hydro (i.e. only Frank's Channel units in service), subject to engineering judgement.

2. The Board approves the use of transmission forced outage rates based on 50:50 weighting of the L199 transmission system historical outage data and CEA-ERIS data for the L 199 transmission system for purposes of the probabilistic LOLE modeling of the Snare Yellowknife system, for system planning purposes.

3. The Board approves the use of average winter water flow and reservoir levels for purposes of determining the hydro capacity to be included in the LOLE model.

4. The Board accepts NWTPC's proposal that MCR of diesel units be used for modeling of the system for capacity planning purposes.

5. Nothing in this Decision and Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

DATED November 29, 2004
John E. Hill
Chairman

REFERENCE:

QUESTION:

Page 3-9 of the Resource Plan states that in 80% of the years (i.e., non-drought years), the Whitehorse Rapids Hydro Plan could reliably provide 24 MW or more during winter.

a) Please state how much capacity can reliably be counted on during non-drought years and include historical records to support your answer.
b) During an N-1 condition, in a drought year, and at the time of the annual peak load, can the output of the Whitehorse Rapids Hydro Plant be increased above 24 MW even if it is for a short period of time? Please elaborate on your answer.

ANSWER:

The reference is to page 3-8 of the Resource Plan and a quote that Yukon Energy provided to the YUB in their 1993/94 GRA. The more recent information assessed by Yukon Energy is that the plant can reliably produce 24 MW during drought years (100% of the time) given current system operating approaches and licence conditions.

a)

During non-drought years, the Whitehorse Rapids plant under today's operating practice can produce above 24 MW during the December through April winter periods. As an example, in the winter of 2003/04 the plant maximum average daily output was at 26.22 MW, in 2004/05 at 28.38 MW, and in 2005/06 at 28.73 MW. See the attached Excel spreadsheet indicating the daily average output and flows for the months of December through April of 2003/04, 2004/05 and 2005/06.

The limitations on Whitehorse Rapids hydro as it is operated today (largely as a static discharge operation) relate primarily to the absolute volume of water available to dispatch over the course of the winter. This includes both the storage that is provided behind the Lewes Dam at the outlet of Marsh Lake (which is drawn down over the winter over a controlled storage range of up to 2.438 meters, an a rough live storage volume of 1350 million cubic metres, or about 57 GW.h) and the inflows that occur to the lake during this period (averaging in the range of 80 cms in early winter but dropping off towards March/April, lower in a drought year[1]). Even in drought conditions Yukon

[1] However, note that drought conditions on this system are less severe than Yukon Energy experiences at Aishihik, where inflows in the range of 30% or normal have been experienced.

Energy's licence (as provided in UCG-YEC-2-5 Attachment 1) provides for "early closures" of the Lewes Dam gates during summer so as to ensure that the water level on the lake will reach the full supply level (1350 mcm) by the start of winter (practically defined as Nov 1 for operations purposes). This basically assured supply of stored water represents a substantial portion of the water that will be used by WH rapids over the season (in the range of 1/2, to as much as approximately 2/3 in a drought) so the variability of outputs at Whitehorse Rapids related to drought versus average flows are not dramatic compared to the output of the plant (within about 4-5 MW, as illustrated above).

b)

Yes. Output can be increased above 24 MW, however it is constrained by two major limiting factors.

- First, short-term output increases are dispatched by drawing down the small amount of storage in Schwatka Lake; however this is limited to about 5 MW.h (so can support, for example, about 1 MW increased output for about 5 hours before needing to be recharged, or 5 MW for 1 hour).
- Second, output cannot be allowed to vary excessively due to ice constraints, particularly during formation of ice cover in low lying areas (which can commonly occur concurrently with very low temperatures, so is a significant concern). Yukon Energy has operationally used the 5 MW.h of Schwatka storage to help meet daily peaks (up to about 0.5 MW to 1.0 MW through the main peaks of the daily load).

Acres did do a preliminary study of this issue as summarized in their 1995 report (provided in YUB-YEC-2-15 Attachment 1) which indicates that the maximum peak daily discharge can be increased above this level so long as this daily cycling is done every day to maintain an ice hinge to shore ice. According to the Acres work, the maximum peak discharges during low flow years (now assumed to be approximately 150 cms average daily discharge) is expected to be about 185 cms (about 29 MW). However, there are two significant limitations to using this capacity: 1) Yukon Energy has not assessed the risks and constraints posed by the operational requirement to exercise this ice hinged regularly (indications are that failing to exercise the hinge for even a short time would eliminate the ability to use it through the remainder of the winter) and 2) as noted above, this level of discharge could only be achieved for a very short period of time (about 1 hour) using Schwatka Lake. Yukon Energy is in the process of retaining ice experts who will be asked to assess this issue towards potential future further upgrading of the Whitehorse Rapids rated capacity.

REFERENCE:

QUESTION:

Page 3-9 of the Resource Plan states: “Recent rewinds performed on AH1 indicate a potential to increase the rating on the units to 15.4 MW. However, rewind work has not yet been performed on AH2 (scheduled for 2006) and until this work is completed and consequent coordinated testing done on the units, YEC will not be able to confirm the slight increase in capacity ratings.”

a) Has the rewind work been completed at AH2?
b) When can the increased capacity (30.8 MW) be counted on?

ANSWER:

a) and b)

AH1 generator was rewound in 2003. AH2 generator is being rewound in 2006, with an October scheduled completion date. Both of the rewinds will result in an increase in the electrical ratings of the machines. This is largely due to the improved coil winding insulation materials that are available today. This uprating changes the limiting factor on the machine from an electrical constraint to a hydraulic or mechanical constraint. The rated mechanical output of each machine is 15.4 MW for a theoretical combined total of 30.8 MW. The first unit to rewound (AH1) has proven that it can deliver 15.4 MW, it remains to be proven that both can deliver 15.4 MW maximum continuous rating (MCR) at the same time. This is because hydraulic limitations of the penstock, wicket gates and tailrace may limit the plant output to less then the 30.8 MW theoretical output. The test of plant capacity can only be conducted after the rewinds are complete and should be completed by the spring of 2007.

Note that this capacity would not increase the Load Charring Capability under the N-1 condition and increase the LCC to an insignificant extent under LOLE (likely less than .01 MW) due to the non-redundancy of the Aishihik transmission line.

REFERENCE:

QUESTION:

In Response to YUB-YEC-1-10, YEC indicates it has conducted an analysis of the capacity projects to determine an optimal sequence, which is based primarily on the practical limitations of size and earliest potential in-service date for each project. This expansion sequence has been provided in the table entitled "WAF System Capacity shortfalls (MW) 2005-2012 under base case loads". With respect to this table:

a) The Carmacks-Stewart line assists with 6 MW on 2009, 5.9 MW in 2010, 5.8 MW in 2011, and 5.6 MW in 2012. Please explain how these figures were arrived at.
b) Was the annual capacity assistance computed as the difference between the firm winter capacity in the MD Grid minus the winter peak load connected to the MD Grid? If no, please explain.
c) If yes, are the figures decreasing each year due to peak load increase in the MD Grid?
d) Is YEC assuming that the annual peak in the WAF always coincides with the annual peak in the MD? Or, has any load diversity between the WAF and the MD Grids been accounted for?
e) The table shows the Carmacks-Stewart transmission line project on line in the year 2009. However, the Resource Plan states that this project will be pursued only if federal funding is provided and if mine loads develop. The table also shows the expansion sequence for the base case loads without mine loads. Therefore, it is unclear as to why the Carmacks-Stewart line has been included. Please clarify.
f) What other alternative projects does YEC propose to be on line by 2009 and beyond, that would meet the planning criteria if the Carmacks-Stewart transmission line does not proceed? (It is not clear from the statements on page 3 of 6 of YEB-YEC-1-10b and the references to Section S1.3 what YEC is specifically proposing to construct at the Whitehorse Rapids Diesel Plant if the Carmacks-Stewart line does not proceed).
g) It is unclear why the refurbished WD3 unit provides 5 MW in 2007 and 5.8 MW in 2008. Please explain.

ANSWER:

a), b), c) and d)

The figures represent the surplus peak period capacity on the Mayo-Dawson system in the respective years compared to loads (including line losses). Generating capacity on the Mayo-Dawson system totals 5.4 MW of hydro and 6.6 MW of diesel. Loads on MD are forecast at 5.5 MW in 2009. This leads to a simple surplus of 6.5 MW of generation in excess of peak loads (i.e., prior to any consideration of unit availability or N-1 events). For the purposes of planning, the benefits of the interconnection in this year are assumed at 6.0 MW, to reflect a) a portion of the generation being required for losses on the new interconnection, and b) load diversity between WAF and MD. Consequently, the benefit to WAF load carrying capability in 2009 is assumed at 6.0 MW. In subsequent years, this value declines with load growth on the MD system.

Yukon Energy has not done any detailed analysis of the normal load diversity between the WAF and MD grids. However, from reviewing individual months the winter loads are almost entirely coincident. For example, in January 2004 the WAF peak occurred when MD was at 98% of its monthly peak. Also note that MD is about 1/10 the size of WAF.

e)

The question is incorrect – no federal funding is expected for the Carmacks-Stewart transmission line project, just Yukon Government funding.

The question is also not entirely clear. The Carmacks-Stewart line is included as YEC is making commitments to construct the project, the project is over $3 million (consistent with the terms of the Minister's June 5 letter) and at least one component of the project is needed to meet YEC commitments and opportunities to service the Minto mine customer.

The Resource Plan indicates that ultimate development of this project is dependent on confirming YTG funding and/or mine loads sufficient to ensure the project's feasibility relative to other options. Analysis provided in the Supplemental Materials (Tab 2) indicates that feasibility of Stage One of this project to Pelly Crossing is particularly sensitive (in a positive way) to confirmation of new mine loads at the Minto mine (which currently is under construction) and the Carmacks Copper mine (which is currently in the licensing stage), and that without one or both of these mine loads significantly more YTG funding will be required for the project to be feasible at this time.

The Carmacks-Stewart project has been included as YEC is fully engaged in the task of planning and licencing this project (see YUB-YEC-2-21) to enable Stage One, if feasible, to proceed in 2008 (to Pelly Crossing) and Stage Two, if feasible, to proceed in 2009 (to Stewart Crossing to complete the interconnection).

The Base Case with Mines near term case is only feasible with new transmission. Stage One of the project will address fully this requirement for the Minto and Carmacks Copper mine examples.

Completion of both Stages One and Two of this project is required to secure the added capacity and energy benefits from interconnection of WAF and MD. Without full interconnection, these benefits will not be secured.

f)

The Resource Plan for the near term addresses the need for contingencies in the event that load requirements vary and/or key factors alter the feasibility of specific resource options. Specific feasibility issues are noted with regard to each of the four proposed near term resource supply projects. The Resource Plan identified alternate diesel generation resource development at the Whitehorse diesel plant; further options have also been subsequently identified.

There are currently three capacity alternatives (contingencies) under active consideration in the event major options in the Resource Plan are not able to proceed in the period to 2012. These continue to be assessed by YEC:

1. **Faro Mirrlees:** There remains a Mirrlees KV16 unit at Faro that was retired after the closure of the Faro mine. This 5 MW unit is being examined as a potential suitable alternative source of near term capacity in the event that one or more of the proposed near term projects cannot proceed as planned, or added capacity is otherwise needed in the near term.
2. **Minto Diesel Plant:** The mine at Minto will be installing a prime power diesel plant to provide its needs during the period prior to the interconnection with YEC's system. Once grid power is available to the mine, about 6.4 MW of diesel generation will become surplus to Minto's requirements, and is currently expected to be sold and removed unless YEC makes alternate arrangements with the mine. The feasibility of YEC securing access to these units for at least the near term as a contingency option is being examined as part of the PPA negotiations with the Minto Mine.

3. **Further Expansion at the Whitehorse Diesel Plant:** In the event that sufficient capacity cannot be secured from the major projects in the Resource Plan, or the above two alternatives, further expansion at the Whitehorse Diesel plant as noted in the Resource Plan is the next identified contingency option. Based on ongoing assessments, the prime focus for this expansion will be on increasing the MW density of the plant in the six "bays" currently occupied by diesel generation[1]. The most likely scenario involves relocating one or more of the three EMD units (2.5, 2.5 and 2.7 MW respectively) and installing into the Whitehorse diesel plant new diesel generation (in the event this is being pursued as a result of one or more of the Mirrlees units being determined to be unsalvageable, the Mirrlees bay is a more likely candidate for this expansion). As set out in the Resource Plan, the most likely size unit is an approximately 8 MW reciprocating unit, of which there are various manufacturers. However, before committing to such a unit, YEC would also give serious consideration to a dual fuel turbine, capable of operating on both fuel oil and natural gas. Such units are potentially well suited to the WAF system, being of large size (14 MW – with highest outputs available in cold weather), flexible in regards to potential future fuel availability (natural gas), and although not as efficient in simple cycle format, lend themselves to later adding a steam turbine (combined cycle) to achieve higher efficiencies than diesel reciprocating engines in the event baseload diesel becomes required on WAF.

In addition to the above contingency options, the Resource Plan notes that Yukon Energy continues to monitor opportunities to cost effectively put in place a second transmission line to Aishihik, which would materially aid in meeting system capacity requirements. Potential opportunities for this option may occur if Life Extension of the Mirrlees is not able to proceed, connection of the WAF and MD grids is not secured, new mine loads are connected to the WAF grid, and feasible short term capacity expansion opportunities are confirmed (e.g., surplus diesel units available at the Minto Mine) that would meet immediate near term capacity needs while the Aishihik Twinning project is being licensed and constructed.

YEC also continues to assess various other capacity enhancement options on the WAF system, including the potential for a 1 MW diesel unit at Carcross (likely by YECL) and cost effective opportunities to re-runner existing hydro units (as set out in the Resource Plan section 3.2.2).

[1] Each of the Mirrlees units occupies a bay, the three EMD units occupy 2 bays, and the Cat unit occupies a bay.

g)

The Mirrlees Life Extension Project benefits are set out in the table below (column on "difference"). With respect to the capacity values in advance of the life extension activities, see YUB-YEC-2-5.

Impact of Mirrlees Life Extension Project on Capacity (MW)

	Mirrlees WD1, 2, and 3 output under retirement scenario				Mirrlees WD1, 2, and 3 output under Life Extension				*difference*
	WD1	WD2	WD3	Total	WD1	WD2	WD3	Total	
2006	3.0	4.2	4.2	11.4	3.0	4.2	4.2	11.4	*0.0*
2007	3.0	4.2	0.0	7.2	3.0	4.2	5.0	12.2	*5.0*
2008	3.0	4.2	0.0	7.2	3.0	5.0	5.0	13.0	*5.8*
2009	3.0	0.0	0.0	3.0	4.0	5.0	5.0	14.0	*11.0*
2010	3.0	0.0	0.0	3.0	4.0	5.0	5.0	14.0	*11.0*
2011	0.0	0.0	0.0	0.0	4.0	5.0	5.0	14.0	*14.0*
2012	0.0	0.0	0.0	0.0	4.0	5.0	5.0	14.0	*14.0*

REFERENCE:

QUESTION:

The expansion sequence presented in Response YUB-YEC-1-10 shows only three projects during the 2006-2012 period, namely Marsh Lake Fall/Winter Storage, Carmacks-Stewart Line, and Mirrlees Life Extension. However, the Aishihik third turbine project is not included as it is of limited firm capacity benefits, even though this project could potentially be put in service by the third quarter of 2008. In this regard:

a) Please confirm that the limited firm capacity of the Aishihik third turbine project is in fact zero under the N-1 criterion.
b) Has YEC considered twinning the portion of the transmission line from Aishihik to Whitehorse as an option? (It would be significantly shorter than the Carmacks-Stewart Line)
c) Would twinning the Aishihik-Whitehorse portion provide 15 MW of firm capacity, as compared to only 6 MW for the Carmacks-Stewart Line, under the N-1 criterion? (A single turbine outage at Aishihik becomes the worst N-1 event)
d) Would twinning the Aishihik-Whitehorse portion and the Marsh Lake Fall/Winter storage projects provide adequate capacity until past 2010 under the N-1 criterion and until 2009 under the LOLE criterion?
e) When would be the earliest that the twinning of the Aishihik-Whitehorse portion and the Aishihik third turbine projects could be on line?
f) Would twinning the Aishihik-Whitehorse line and the Aishihik third turbine meet both the N-1 and LOLE criteria?

ANSWER:

a)

Confirmed. Although the Aishihik 3rd Turbine can provide 7MW of peaking capability it does not provide any firm capacity under the N-1 criterion because it is at the end of the Aishihik line. It provides 0.6 MW under the LOLE criterion.

b)

Yes, YEC has considered twinning the portion of the transmission line from Aishihik to Whitehorse as discussed in Chapter 4 of the 20-Year Resource Plan (pg 4-34). The “twinning” option has primarily been considered using largely the same route as the existing line with the exception of the last section connecting into Whitehorse, which will be expected to follow the Alaska Highway to the McIntyre substation or the Whitehorse dam site (rather than into the Takhini substation as for the existing line). Also see attachment: YUB-YEC-2-11 Attachment 1.

c)

Although twinning the Aishihik-Whitehorse portion would provide approximately 15 MW[1] of firm capacity under N-1 criterion it only provides 8.0 MW of firm capacity under the LOLE criterion (which becomes relevant under the Base Case with Mines load scenario). A single turbine outage (15MW) at Aishihik becomes the worst N-1 event with twinning of the Aishihik line. Following construction of the Aishihik 3rd turbine, the benefits of an Aishihik 2nd transmission line grow to 22 MW under the N-1 criteria and approximately 14.4 MW under the LOLE.

With respect to Carmacks-Stewart firm capacity contribution, due to ongoing MD load growth the benefit by 2012 is only 5.6 MW, not 6.0 MW.

In comparing the Carmacks-Stewart Transmission Project and the Aishihik Twinning Transmission Project, the Resource Plan has considered the following factors in addition to access to added capacity benefits:

- **Access to new firm near term loads to utilize surplus hydro resources** – Stage One of the Carmacks Stewart Project offers the opportunity for access to material potential new near term loads that would displace diesel generation (GHG emission reductions and mine operation cost savings impacts) and utilize WAF surplus hydro generation. No similar new near term load opportunities are presented by the Aishihik Twinning Project.
- **Long-term system efficiency, flexibility and development benefits as well as regional development benefits** – Connection of the WAF and MD grids offers Yukon these overall long term benefits from integrated planning and operation of these two grids. These benefits, plus economic and other development benefits along the transmission corridor for the local First Nations (as confirmed in the MOU with the NTFN), communities and resources are key factors explain why connection of the two grids has been an ongoing long-term objective for power resource planning. In contrast, the Aishihik Twinning Project

[1] 15 MW for 1 turbine at Aishihik, plus the line would allow the diesel at Haines Junction to contribute to serving WAF loads under an N-1 condition to the extent that unit is not fully utilized to supply local Haines Junction loads. In the Resource Plan modelling, this benefit is assumed at 0.3 MW.

would not provide new grid access to any region or offer other benefits of the type noted.

- **Near term opportunity for YTG Infrastructure Funding** – This specific near term opportunity, reflecting the combined effect of the broad and material potential near and long term benefits noted above, was a key factor affecting YEC's initial planning for the Carmacks-Stewart Project. No similar opportunity for such YTG funding was identified for the Aishihik Twinning Project.
- **Near term options and needs to secure WAF capacity resources -** The single factor highlighted by the Aishihik Twinning Project options was provision of capacity benefits. However, other options (e.g., the Mirrlees Life Extension) were also available with a similar overall size of capacity benefits that offered potentially much lower costs per MW as well as faster implementation, and less lumpy and risky implementation.

In summary, the Carmacks Stewart Project is being proposed in response to specific near term opportunities as noted above that do not apply to the Aishihik Twinning Project. The primary focus for the Carmacks Stewart Project is not to secure the capacity benefits. (see YUB-YEC-2-21).

d), e) and f)

Twinning the Aishihik-Whitehorse portion along with the Marsh Lake Fall/Winter Storage project would provide the following results assuming Aishihik 2nd Transmission line is completed in 2009[2], and the Aishihik 3rd turbine in 2009.

- Under all scenarios, there would be shortfalls in 2006-2008 prior to bringing the Aishihik 2nd transmission line into service (due to load growth and the scheduled retirement of WD3).
- Following 2009, there would be adequate capacity in under the **Base Case Load Forecast**. Next capacity would not be required until about 2017.
- In the ***Low Sensitivity Load Forecast*** there would be adequate capacity throughout almost the entire the 20 year Resource Plan period (to about 2023).
- In the ***Base Case Load Forecast with 2 Mines*** scenario there would start to be shortfalls in 2011 coinciding with the retirement of the last of the Mirrlees units. This shortfall by 2012 approximates 4.9 MW.

[2] Note however that at this point, it is very unlikely that YEC could complete the Aishihik 2nd transmission line for service in 2009 given planning and environmental licencing requirements. This time frame is being considered today for Carmacks Stewart, after a year's intensive planning and several prior years of study. Intensive planning for the Aishihik 2nd transmission line, as well as initial studies, have both not yet been feasible to pursue.

- In the ***High Sensitivity Load Forecast***, there would be shortfalls in every year from 2006-2012, up to about 10.1 MW.

These values are shown in the attached three-part table. The top portion of the sheet (called Table 1) is the LOLE criterion and the bottom portion of the sheet (Table 2) is the N-1 criterion. Table 3 shows the capacity driver in terms of N-1 or LOLE (drawn from Table 1 and Table 2) to give a summary picture of the overall surplus/shortfall.

The 20-Year Resource Plan indicates on page 4-35, based on information at the time the plan was prepared, that the earliest that the Aishihik 2nd Transmission Line could expect to be in service is 2009. However, based on current information, this is not likely possible now until 2010 at the earliest even if intensive planning work was to be initiated at this time.

As set out in the following tables:

- **Tables 4, 5 and 6 contain the analysis for the 2nd Transmission line and Marsh Lake as asked for in (d):** The question is not confirmed. In summary, twinning the Aishihik Transmission Line along with Marsh Lake storage, but with Mirrlees retired as assumed in 2007, 2009, and 2011 would lead to shortfalls through 2008 prior to the line coming into service, and afterwards both criteria would be met in 2009 and 2010 and begin to be exceeded in 2011 under base case loads.
- **Tables 7, 8 and 9 contain the analysis for the 2nd Transmission line and the Aishihik third turbine as asked for in (f):** The question is not confirmed. These tables indicate twinning the Aishihik Transmission Line with an Aishihik 3rd turbine (assuming Mirrlees retired in 2007, 2009, and 2011) would lead to shortfalls through 2008 prior to the line coming into service, and afterwards both criteria would be exceeded throughout the planning horizon to 2012 under base case loads.

Marsh Lake Fall/Winter Storage, Aishihik 2nd T-line and Aishihik 3rd Turbine Projects
YUB-YEC-2-11d,e,f

Table 1: LOLE Calculations

Year	System Load Conditions: WAF Peak Load (MW)	System Load Conditions: LOLE Shortfall (MW)	Projects: Marsh Fall/Winter Storage - 2007	Projects: Aishihik 2nd T-line - 2009	Projects: Aishihik 3rd Turbine-2009	Resulting WAF System Balance (Shortfall indicates req. for new diesel)
Base Case Load Forecast (also reflects Base Case with Minto)						
2005	56.4	6.5				6.5
2006	57.4	5.5				5.5
2007	58.5	0.2	1.6			1.8
2008	59.6	(0.9)	1.6			0.7
2009	60.6	(6.1)	1.6	8.0	7.0	10.5
2010	61.7	(7.2)	1.6	8.0	7.0	9.4
2011	62.9	(11.4)	1.6	8.0	7.0	5.2
2012	64.0	(12.5)	1.6	8.0	7.0	4.1
Low Sensitivity Load Forecast						
2005	56.4	6.5				6.5
2006	56.9	6.0				6.0
2007	57.4	1.3	1.6			2.9
2008	57.9	0.8	1.6			2.4
2009	58.4	(3.9)	1.6	8.0	7.0	12.7
2010	59.0	(4.5)	1.6	8.0	7.0	12.1
2011	59.5	(8.0)	1.6	8.0	7.0	8.6
2012	60.0	(8.5)	1.6	8.0	7.0	8.1
Base Case Load Forecast with 2 Mines (Minto & CC)						
2005	56.4	6.5				6.5
2006	57.4	5.5				5.5
2007	60.5	(1.8)	1.6			(0.2)
2008	68.6	(9.9)	1.6			(8.3)
2009	69.6	(15.1)	1.6	8.0	7.0	1.5
2010	70.7	(16.2)	1.6	8.0	7.0	0.4
2011	71.9	(20.4)	1.6	8.0	7.0	(3.8)
2012	73.0	(21.5)	1.6	8.0	7.0	(4.9)
High Sensitivity Load Forecast (including Minto and CC)						
2005	56.4	6.5				6.5
2006	58.1	4.8				4.8
2007	61.8	(3.1)	1.6			(1.5)
2008	70.6	(11.9)	1.6			(10.3)
2009	72.4	(17.9)	1.6	8.0	7.0	(1.3)
2010	74.3	(19.8)	1.6	8.0	7.0	(3.2)
2011	76.2	(24.7)	1.6	8.0	7.0	(8.1)
2012	78.2	(26.7)	1.6	8.0	7.0	(10.1)

Note: When Aishihik 2nd T-line is connected gain MWs from Aishihik 3rd Turbine as reliable capacity

Table 3: Summary

Resulting WAF System Balance: LOLE Shortfall (MW)	Resulting WAF System Balance: N-1 Shortfall (MW)	Capacity Driver	Surplus/ (shortfall)
6.5	0.3	N-1	0.3
5.5	(0.7)	N-1	(0.7)
1.8	(4.4)	N-1	(4.4)
0.7	(5.5)	N-1	(5.5)
10.5	11.6	LOLE	10.5
9.4	10.5	LOLE	9.4
5.2	6.3	LOLE	5.2
4.1	5.2	LOLE	4.1
6.5	0.3	N-1	0.3
6.0	(0.2)	N-1	(0.2)
2.9	(3.3)	N-1	(3.3)
2.4	(3.8)	N-1	(3.8)
12.7	13.8	LOLE	12.7
12.1	13.2	LOLE	12.1
8.6	9.7	LOLE	8.6
8.1	9.2	LOLE	8.1
6.5	0.3	N-1	0.3
5.5	(0.7)	N-1	(0.7)
(0.2)	(4.4)	N-1	(4.4)
(8.3)	(5.5)	LOLE	(8.3)
1.5	11.6	LOLE	1.5
0.4	10.5	LOLE	0.4
(3.8)	6.3	LOLE	(3.8)
(4.9)	5.2	LOLE	(4.9)
6.5	0.3	N-1	0.3
4.8	(1.4)	N-1	(1.4)
(1.5)	(5.7)	N-1	(5.7)
(10.3)	(7.5)	LOLE	(10.3)
(1.3)	8.8	LOLE	(1.3)
(3.2)	6.9	LOLE	(3.2)
(8.1)	2.0	LOLE	(8.1)
(10.1)	(0.0)	LOLE	(10.1)

Table 2: N-1 Calculations

Year	System Load Conditions: WAF Peak Load (MW)	System Load Conditions: N-1 Shortfall (MW)	Projects: Marsh Fall/Winter Storage - 2007	Projects: Aishihik 2nd T-line - 2009	Projects: Aishihik 3rd Turbine-2009	Resulting WAF System Balance (Shortfall indicates req. for new diesel)
Base Case Load Forecast (also reflects Base Case with Minto)						
2005	56.4	0.3				0.3
2006	57.4	(0.7)				(0.7)
2007	58.5	(6.0)	1.6			(4.4)
2008	59.6	(7.1)	1.6			(5.5)
2009	60.6	(12.3)	1.6	15.3	7.0	11.6
2010	61.7	(13.4)	1.6	15.3	7.0	10.5
2011	62.9	(17.6)	1.6	15.3	7.0	6.3
2012	64.0	(18.7)	1.6	15.3	7.0	5.2
Low Sensitivity Load Forecast						
2005	56.4	0.3				0.3
2006	56.9	(0.2)				(0.2)
2007	57.4	(4.9)	1.6			(3.3)
2008	57.9	(5.4)	1.6			(3.8)
2009	58.4	(10.1)	1.6	15.3	7.0	13.8
2010	59.0	(10.7)	1.6	15.3	7.0	13.2
2011	59.5	(14.2)	1.6	15.3	7.0	9.7
2012	60.0	(14.7)	1.6	15.3	7.0	9.2
Base Case Load Forecast with 2 Mines (Minto & CC)						
2005	56.4	0.3				0.3
2006	57.4	(0.7)				(0.7)
2007	60.5	(6.0)	1.6			(4.4)
2008	68.6	(7.1)	1.6			(5.5)
2009	69.6	(12.3)	1.6	15.3	7.0	11.6
2010	70.7	(13.4)	1.6	15.3	7.0	10.5
2011	71.9	(17.6)	1.6	15.3	7.0	6.3
2012	73.0	(18.7)	1.6	15.3	7.0	5.2
High Sensitivity Load Forecast (including Minto and CC)						
2005	56.4	0.3				0.3
2006	58.1	(1.4)				(1.4)
2007	61.8	(7.3)	1.6			(5.7)
2008	70.6	(9.1)	1.6			(7.5)
2009	72.4	(15.1)	1.6	15.3	7.0	8.8
2010	74.3	(17.0)	1.6	15.3	7.0	6.9
2011	76.2	(21.9)	1.6	15.3	7.0	2.0
2012	78.2	(23.9)	1.6	15.3	7.0	(0.0)

1 Note: When Aishihik 2nd T-line is connected gain MWs from Aishihik 3rd Turbine as reliable capacity

Aishihik 2nd T-line and Marsh Lake Fall/Winter Storage Projects
YUB-YEC-2-11d

Table 4: LOLE Calculations / Table 6: Summary

Year	System Load Conditions: WAF Peak Load (MW)	System Load Conditions: LOLE Shortfall (MW)	Projects: Marsh Fall/Winter Storage - 2007	Projects: Aishihik 2nd T-line - 2009	Resulting WAF System Balance (Shortfall indicates req. for new diesel)	Table 6 – Resulting WAF System Balance: LOLE Shortfall (MW)	Table 6 – Resulting WAF System Balance: N-1 Shortfall (MW)	Capacity Driver	Surplus/ (shortfall)
Base Case Load Forecast (also reflects Base Case with Minto)									
2005	56.4	6.5			6.5	6.5	0.3	N-1	0.3
2006	57.4	5.5			5.5	5.5	(0.7)	N-1	(0.7)
2007	58.5	0.2	1.6		1.8	1.8	(4.4)	N-1	(4.4)
2008	59.6	(0.9)	1.6		0.7	0.7	(5.5)	N-1	(5.5)
2009	60.6	(6.1)	1.6	8.0	3.5	3.5	4.6	LOLE	3.5
2010	61.7	(7.2)	1.6	8.0	2.4	2.4	3.5	LOLE	2.4
2011	62.9	(11.4)	1.6	8.0	(1.8)	(1.8)	(0.7)	LOLE	(1.8)
2012	64.0	(12.5)	1.6	8.0	(2.9)	(2.9)	(1.8)	LOLE	(2.9)
Low Sensitivity Load Forecast									
2005	56.4	6.5			6.5	6.5	0.3	N-1	0.3
2006	56.9	6.0			6.0	6.0	(0.2)	N-1	(0.2)
2007	57.4	1.3	1.6		2.9	2.9	(3.3)	N-1	(3.3)
2008	57.9	0.8	1.6		2.4	2.4	(3.8)	N-1	(3.8)
2009	58.4	(3.9)	1.6	8.0	5.7	5.7	6.8	LOLE	5.7
2010	59.0	(4.5)	1.6	8.0	5.1	5.1	6.2	LOLE	5.1
2011	59.5	(8.0)	1.6	8.0	1.6	1.6	2.7	LOLE	1.6
2012	60.0	(8.5)	1.6	8.0	1.1	1.1	2.2	LOLE	1.1
Base Case Load Forecast with 2 Mines (Minto & CC)									
2005	56.4	6.5			6.5	6.5	0.3	N-1	0.3
2006	57.4	5.5			5.5	5.5	(0.7)	N-1	(0.7)
2007	60.5	(1.8)	1.6		(0.2)	(0.2)	(4.4)	N-1	(4.4)
2008	68.6	(9.9)	1.6		(8.3)	(8.3)	(5.5)	LOLE	(8.3)
2009	69.6	(15.1)	1.6	8.0	(5.5)	(5.5)	4.6	LOLE	(5.5)
2010	70.7	(16.2)	1.6	8.0	(6.6)	(6.6)	3.5	LOLE	(6.6)
2011	71.9	(20.4)	1.6	8.0	(10.8)	(10.8)	(0.7)	LOLE	(10.8)
2012	73.0	(21.5)	1.6	8.0	(11.9)	(11.9)	(1.8)	LOLE	(11.9)
High Sensitivity Load Forecast (including Minto and CC)									
2005	56.4	6.5			6.5	6.5	0.3	N-1	0.3
2006	58.1	4.8			4.8	4.8	(1.4)	N-1	(1.4)
2007	61.8	(3.1)	1.6		(1.5)	(1.5)	(5.7)	N-1	(5.7)
2008	70.6	(11.9)	1.6		(10.3)	(10.3)	(7.5)	LOLE	(10.3)
2009	72.4	(17.9)	1.6	8.0	(8.3)	(8.3)	1.8	LOLE	(8.3)
2010	74.3	(19.8)	1.6	8.0	(10.2)	(10.2)	(0.1)	LOLE	(10.2)
2011	76.2	(24.7)	1.6	8.0	(15.1)	(15.1)	(5.0)	LOLE	(15.1)
2012	78.2	(26.7)	1.6	8.0	(17.1)	(17.1)	(7.0)	LOLE	(17.1)

Table 5: N-1 Calculations

Year	System Load Conditions: WAF Peak Load (MW)	System Load Conditions: N-1 Shortfall (MW)	Projects: Marsh Fall/Winter Storage - 2007	Projects: Aishihik 2nd T-line - 2009	Resulting WAF System Balance (Shortfall indicates req. for new diesel)
Base Case Load Forecast (also reflects Base Case with Minto)					
2005	56.4	0.3			0.3
2006	57.4	(0.7)			(0.7)
2007	58.5	(6.0)	1.6		(4.4)
2008	59.6	(7.1)	1.6		(5.5)
2009	60.6	(12.3)	1.6	15.3	4.6
2010	61.7	(13.4)	1.6	15.3	3.5
2011	62.9	(17.6)	1.6	15.3	(0.7)
2012	64.0	(18.7)	1.6	15.3	(1.8)
Low Sensitivity Load Forecast					
2005	56.4	0.3			0.3
2006	56.9	(0.2)			(0.2)
2007	57.4	(4.9)	1.6		(3.3)
2008	57.9	(5.4)	1.6		(3.8)
2009	58.4	(10.1)	1.6	15.3	6.8
2010	59.0	(10.7)	1.6	15.3	6.2
2011	59.5	(14.2)	1.6	15.3	2.7
2012	60.0	(14.7)	1.6	15.3	2.2
Base Case Load Forecast with 2 Mines (Minto & CC)					
2005	56.4	0.3			0.3
2006	57.4	(0.7)			(0.7)
2007	60.5	(6.0)	1.6		(4.4)
2008	68.6	(7.1)	1.6		(5.5)
2009	69.6	(12.3)	1.6	15.3	4.6
2010	70.7	(13.4)	1.6	15.3	3.5
2011	71.9	(17.6)	1.6	15.3	(0.7)
2012	73.0	(18.7)	1.6	15.3	(1.8)
High Sensitivity Load Forecast (including Minto and CC)					
2005	56.4	0.3			0.3
2006	58.1	(1.4)			(1.4)
2007	61.8	(7.3)	1.6		(5.7)
2008	70.6	(9.1)	1.6		(7.5)
2009	72.4	(15.1)	1.6	15.3	1.8
2010	74.3	(17.0)	1.6	15.3	(0.1)
2011	76.2	(21.9)	1.6	15.3	(5.0)
2012	78.2	(23.9)	1.6	15.3	(7.0)

Aishihik 2nd T-line and Aishihik Third Turbine
YUB-YEC-2-11f

Table 7: LOLE Calculations

Year	System Load Conditions: WAF Peak Load (MW)	System Load Conditions: LOLE Shortfall (MW)	Projects: Aishihik 3rd turbine - 2009	Projects: Aishihik 2nd T-line - 2009	Resulting WAF System Balance (Shortfall indicates req. for new diesel)
Base Case Load Forecast (also reflects Base Case with Minto)					
2005	56.4	6.5			6.5
2006	57.4	5.5			5.5
2007	58.5	0.2			0.2
2008	59.6	(0.9)			(0.9)
2009	60.6	(6.1)	7.0	8.0	8.9
2010	61.7	(7.2)	7.0	8.0	7.8
2011	62.9	(11.4)	7.0	8.0	3.6
2012	64.0	(12.5)	7.0	8.0	2.5
Low Sensitivity Load Forecast					
2005	56.4	6.5			6.5
2006	56.9	6.0			6.0
2007	57.4	1.3			1.3
2008	57.9	0.8			0.8
2009	58.4	(3.9)	7.0	8.0	11.1
2010	59.0	(4.5)	7.0	8.0	10.5
2011	59.5	(8.0)	7.0	8.0	7.0
2012	60.0	(8.5)	7.0	8.0	6.5
Base Case Load Forecast with 2 Mines (Minto & CC)					
2005	56.4	6.5			6.5
2006	57.4	5.5			5.5
2007	60.5	(1.8)			(1.8)
2008	68.6	(9.9)			(9.9)
2009	69.6	(15.1)	7.0	8.0	(0.1)
2010	70.7	(16.2)	7.0	8.0	(1.2)
2011	71.9	(20.4)	7.0	8.0	(5.4)
2012	73.0	(21.5)	7.0	8.0	(6.5)
High Sensitivity Load Forecast (including Minto and CC)					
2005	56.4	6.5			6.5
2006	58.1	4.8			4.8
2007	61.8	(3.1)			(3.1)
2008	70.6	(11.9)			(11.9)
2009	72.4	(17.9)	7.0	8.0	(2.9)
2010	74.3	(19.8)	7.0	8.0	(4.8)
2011	76.2	(24.7)	7.0	8.0	(9.7)
2012	78.2	(26.7)	7.0	8.0	(11.7)

Note: When Aishihik 2nd T-line is connected gain MWs from Aishihik 3rd Turbine as reliable capacity

Table 9: Summary

Year	Resulting WAF System Balance: LOLE Shortfall (MW)	Resulting WAF System Balance: N-1 Shortfall (MW)	Capacity Driver	Surplus/ (shortfall)
Base Case Load Forecast (also reflects Base Case with Minto)				
2005	6.5	0.3	N-1	0.3
2006	5.5	(0.7)	N-1	(0.7)
2007	0.2	(6.0)	N-1	(6.0)
2008	(0.9)	(7.1)	N-1	(7.1)
2009	8.9	10.0	LOLE	8.9
2010	7.8	8.9	LOLE	7.8
2011	3.6	4.7	LOLE	3.6
2012	2.5	3.6	LOLE	2.5
Low Sensitivity Load Forecast				
2005	6.5	0.3	N-1	0.3
2006	6.0	(0.2)	N-1	(0.2)
2007	1.3	(4.9)	N-1	(4.9)
2008	0.8	(5.4)	N-1	(5.4)
2009	11.1	12.2	LOLE	11.1
2010	10.5	11.6	LOLE	10.5
2011	7.0	8.1	LOLE	7.0
2012	6.5	7.6	LOLE	6.5
Base Case Load Forecast with 2 Mines (Minto & CC)				
2005	6.5	0.3	N-1	0.3
2006	5.5	(0.7)	N-1	(0.7)
2007	(1.8)	(6.0)	N-1	(6.0)
2008	(9.9)	(7.1)	LOLE	(9.9)
2009	(0.1)	10.0	LOLE	(0.1)
2010	(1.2)	8.9	LOLE	(1.2)
2011	(5.4)	4.7	LOLE	(5.4)
2012	(6.5)	3.6	LOLE	(6.5)
High Sensitivity Load Forecast (including Minto and CC)				
2005	6.5	0.3	N-1	0.3
2006	4.8	(1.4)	N-1	(1.4)
2007	(3.1)	(7.3)	N-1	(7.3)
2008	(11.9)	(9.1)	LOLE	(11.9)
2009	(2.9)	7.2	LOLE	(2.9)
2010	(4.8)	5.3	LOLE	(4.8)
2011	(9.7)	0.4	LOLE	(9.7)
2012	(11.7)	(1.6)	LOLE	(11.7)

Table 8: N-1 Calculations

Year	System Load Conditions: WAF Peak Load (MW)	System Load Conditions: N-1 Shortfall (MW)	Projects: Aishihik 3rd turbine - 2009	Projects: Aishihik 2nd T-line - 2009	Resulting WAF System Balance (Shortfall indicates req. for new diesel)
Base Case Load Forecast (also reflects Base Case with Minto)					
2005	56.4	0.3			0.3
2006	57.4	(0.7)			(0.7)
2007	58.5	(6.0)			(6.0)
2008	59.6	(7.1)			(7.1)
2009	60.6	(12.3)	7.0	15.3	10.0
2010	61.7	(13.4)	7.0	15.3	8.9
2011	62.9	(17.6)	7.0	15.3	4.7
2012	64.0	(18.7)	7.0	15.3	3.6
Low Sensitivity Load Forecast					
2005	56.4	0.3			0.3
2006	56.9	(0.2)			(0.2)
2007	57.4	(4.9)			(4.9)
2008	57.9	(5.4)			(5.4)
2009	58.4	(10.1)	7.0	15.3	12.2
2010	59.0	(10.7)	7.0	15.3	11.6
2011	59.5	(14.2)	7.0	15.3	8.1
2012	60.0	(14.7)	7.0	15.3	7.6
Base Case Load Forecast with 2 Mines (Minto & CC)					
2005	56.4	0.3			0.3
2006	57.4	(0.7)			(0.7)
2007	60.5	(6.0)			(6.0)
2008	68.6	(7.1)			(7.1)
2009	69.6	(12.3)	7.0	15.3	10.0
2010	70.7	(13.4)	7.0	15.3	8.9
2011	71.9	(17.6)	7.0	15.3	4.7
2012	73.0	(18.7)	7.0	15.3	3.6
High Sensitivity Load Forecast (including Minto and CC)					
2005	56.4	0.3			0.3
2006	58.1	(1.4)			(1.4)
2007	61.8	(7.3)			(7.3)
2008	70.6	(9.1)			(9.1)
2009	72.4	(15.1)	7.0	15.3	7.2
2010	74.3	(17.0)	7.0	15.3	5.3
2011	76.2	(21.9)	7.0	15.3	0.4
2012	78.2	(23.9)	7.0	15.3	(1.6)

Note: When Aishihik 2nd T-line is connected gain MWs from Aishihik 3rd Turbine as reliable capacity

AISHIHIK TRANSMISSION 2ND LINE PROJECT INITIAL PLANNING CONCEPTS

PURPOSE

The following sets out initial planning concepts for the Aishihik Transmission 2nd Line Project. This Project is being considered by Yukon Energy for potential development as soon as is feasible in the event that:

a) adoption of the new capacity planning criteria indicate capacity shortfalls on the Whitehorse-Aishihik-Faro (WAF) grid related to the current Aishihik Transmission Line (L171);
b) the existing Mirrless diesel units at Whitehorse are confirmed to be retired in an orderly fashion.

BACKGROUND

The Yukon Energy (YEC) WAF grid is a 138 kV transmission system connecting approximately 30 MW of hydro generation at Aishihik with major load and generation centers at Whitehorse (40 MW installed hydro plus 25 MW of nameplate diesel generation) and Faro (major diesel plant of 5.3 MW) as well as a number of smaller load centers (including in particular Carmacks) and lower voltage connections to other small communities (southeast to Teslin, and seperately east to Ross River, as well as south to Haines Junction).

Recent assessment of the WAF system reliability indicates the existing Aishihik Transmission Line (L171) connecting the Aishihik GS to the WAF grid is a key weakness or “bottleneck” in reliably ensuring adequate generation on the WAF grid to support winter peak loads. In addition, one of the more promising possible near-term capacity additions involves adding an approximately 7 MW third turbine to Aishihik GS. Consequently, the potential Aishihik Transmision 2nd Line Project (the “Project”) is a means to assess and potentially address this bottleneck via developing redundancy in transmission.

OVERVIEW OF EXISTING SYSTEM

The Aishihik GS in western Yukon is the key multi-year storage hydro facility on the WAF grid. As such, it is a critical component of supplying winter peak demands, particuarly during periods of low water at the Whitehorse Rapids GS, a largely run-of-the-river plant within the boundaries of Whitehorse.

The Aishihik GS supply is connected to Whitehorse and beyond on the WAF grid by L171, an approximately 130 km 138 kV wood H-frame construction transmission line. The line was constructed in 1975 and connects the substation at Aishihik (S167) with substation facilities at Takhini (S164, approximately 10 km north of Whitehorse).

The line resides in a 200 foot wide right-of-way with all required permits and easements. Initial GIS mapping indicates the line is approximately centered in the right-of-way.

The current Aishihik line has a number of Potential Transformer (PT) connections to service small loads in the vicinity, which may increase exposure to outages.

The routing of the existing line is south from the Aishihik GS for approximately 20 km to the vicinity of the Alaska Highway. The line then follows the highway for approximately 60 km. About 40 km west of Whitehorse, the line continues on the north side of the Takhini River (the highway crosses to the south side) and remains on the north side until its termination at Takhini substation S164 on the immediate west side of the Yukon River.

Separate transmission (138 kV line L172) extends south to Whitehorse (25 km in length, crossing the Yukon River adjacent to the Takhini substation and continuing east of the Yukon River) to the YECL Riverside substation S171. About midway between Takhini and Riverside, the 138 kV transmission line L169 taps off L172 and heads east across the Yukon River for about 6.62 km to the McIntyre substation S170 (above the airport, west of the Yukon River). A fourth Whitehorse area substation, S150, is located at the Whitehorse Rapids GS, directly across the river from the Riverside substation. Due to this configuration, supply to Whitehorse from Aishihik is similarly at risk from L172 outages as from L171; however, given that L172 is much shorter and is closer to potential repair crews, the risks have traditionally been considered less pronounced than for L171.

In terms of transformation, at the Aishihik substation there is currently fully redundant transformation (two 30 MVA transformers). However, there are modest redundancy issues with respect to other configuration related to Aishihik GS and substation.

Although discussion to date focuses on reliability issues, the non-redundancy of the Aishihik line also gives rise to operational issues, as it is difficult to allow the line to be taken out of service for maintenance due to the complete loss of Aishihik generation when this occurs. As a result, maintenance activities are difficult to schedule, are frequently cancelled on short notice due to problems at other locations on the grid (making Aishihik generation all the more critical) and are costly, due to the need to potentially run diesel generation when Aishihik hydro is removed from system supply.

Beyond the existing Aishihik transmission line connecting Aishihik GS east to Whitehorse, the 138 kV WAF grid extends north from Whitehorse to Carmacks, a point approximately equidistant from Aishihik as Whitehorse. A recent transmission line development scenario prepared for YEC by Andy Sturton briefly considered a potential Aishihik-Carmacks link as one alterative design concept (but did not extensively review technical concept, merits or other alternatives).

PROJECT CONCEPT

The Project concept discussed to date relates to removing the "single point failure" exposure related to the Aishihik transmission line L171. Two main concepts are currently being simultaneously explored in this regard:

- One concept seeks to reduce exposure to the transmission line weaknesses through reducing the potential impact of outages, focused on installing new diesel or other generation on the WAF grid not dependent on L171.
- The Aishihik Transmission Line Project concept seeks to reduce exposure to weaknesses through reducing the potential incidence and duration of outages, largely through developing redundancy in the transmission connection.

The Project reviewed in this document focuses on the latter concept.

The Project as conceived will be subject to review by the Yukon Utilities Board (YUB) as a YEC investment in its regulated electrical system and rate base. This will require YUB approval before the costs of the Project can be included in Yukon Energy's rate base and be included in the rates charged to Yukon electrical ratepayers. In addition, the Project concept is expected to be reviewed at an expected 2006 YUB hearing reviewing a Yukon Energy 20 Year Resource Plan. This includes expected detailed reviewed of Yukon Energy's reliability study, and proposed changes to the WAF reliability criteria to recognize in system capacity planning the inherent weakness in the current Aishihik transmission line L171.

INITIAL TECHNICAL CONSIDERATIONS

There has been limited technical analysis to date of issues and options related to the Project. Initial discussions have focused on the following:

- **Line voltage of 138 kV:** Due to existing line and substation configuration, it is expected that a voltage of 138 kV will be required. Options for a 34 kV DC connection were investigated but ruled out due to cost.
- **"Express" Configuration:** In all likelihood the system will benefit from the new line being developed and maintained without any PT connections or the like to maximize the integrity of the line for reliability purposes. This means that when the existing L171 is taken down for maintenance, small mobile diesel generation may be required to serve customers who normally receive service through PTs, but this is likely to be considered preferable to a second line with similar integrity to L171.
- **Redundancy at Aishihik GS –** Initial review indicates some modest reconfiguration necessary at the Aishihik substation, involving replacement of a small feeder and addition of a new circuit breaker.
- **Redundancy at eastern terminus substation –** It will be necessary to assess whether there are redundancy issues with respect to the Project's eastern terminus substation (see discussion below regarding related routing options).

Further consideration should be given to the potential that, in future, an Alaska Highway pipeline will be developed with material electrical pumping loads in western Yukon, and to ensuring that any second transmission line is able in that event to assist in supplying such loads from existing generation as well as potential major new generation developed elsewhere on the WAF grid.

ROUTING OPTIONS

Although no extensive review has occurred to date, two main concepts have been identified for the Project, with a number of sub-options:

1) **Aishihik-Carmacks:** As noted above, initial discussion has occurred about the potential to connect Aishihik to the WAF by a major second route well north of the existing line. This option would likely involve material need for substation investment at Carmacks, but would maximize geographic separation. This option would not eliminate the existing Whitehorse exposure to

L172, as all Aishihik generation would continue to be delivered to Whitehorse via this connection. It is not apparent that this option provides material benefits over and above other available options, with the exception of separation.

2) **Aishihik-Whitehorse:** A second major routing option involves roughly "twinning" the Aishihik line L171 between Aishihik GS and Whitehorse. Five main configuration options exist:
    a. **Aishihik-Takhini:** The simplest option is to parallel the existing line functionally between Aishihik and the Takhini substation. This does not necessarily mean routing the two lines in close proximity, but in all likelihood geography and licencing considerations will require development of this option in close parallel to the existing line (as reviewed below). Note that this option also requires developing redundancy on the L172 connection through to either McIntyre substation (S170) or Riverside substation.
    b. **Aishihik-McIntyre; highway route:** A second alternative involves connecting Aishihik directly to the McIntyre substation by a route roughly paralleling the Alaska Highway. This approach will in all likelihood involve being within or adjacent to the existing right-of-way for about 80-90 km, and then establishing a new right-of-way near the highway for about 40 km, to McIntyre substation. No consideration to date has been given to the McIntyre substation and what, if any, reconfiguration will be necessary to allow this connection. In addition, although it is expected this approach will reduce or eliminate Whitehorse exposure to both L171 and L172 outages, this must be further confirmed based on L172/L169 configuration.
    c. **Aishihik-S150; highway route:** A third option is to develop the transmission line roughly as described in option 2b, but rather than connecting to the McIntyre substation, continue the line down a roughly highway route eventually dropping in elevation to connect to the YEC S150 substation at Whitehorse Rapids. YEC technical staff have indicated this is likely the most complete redundancy of the options noted, minimizing exposure to both L171 and L172.

   Two additional potential options that may require consideration involve permutations on options 2b and 2c which would route the line much farther south via an "Ibex Valley" route roughly departing the Alaska highway at the Ibex Valley and passing roughly in the vicinity of Louise Lake and down Fish Lake Road. No detailed review has been conducted on the feasibility or practicality of these options.

It is unlikely that any route other than Option 1 (Aishihik-Carmacks) can avoid close geographic vicinity to the existing line for the first 80-90 km from Aishihik GS, as the existing route and highway follow the only logical geographic features through this region.

INITIAL ENVIRONMENTAL/LICENCING CONSIDERATIONS

The process of licencing the Project has not to date received any review, beyond noting that routing options which maintain the Project within (or potentially adjacent to) the existing right-of-way may be considerably less costly and time-consuming for licencing. It is also likely that new routes up the Ibex Valley will have increased difficulties on various matters compared with new routes that largely follow developed highways (the Ibex Valley is on occasion considered a main area for "remote wilderness" activities within the vicinity of Whitehorse), but these matters require more review before reliable conclusions can be drawn.

No review has been conducted with respect to potential First Nations issues on any of the above routing concepts.

Based on reviews of timing for a separate 138 kV transmission line project in Yukon, it is likely that the project will practically target an ISD of fall 2009 if all planning and approvals can proceed promptly, However for planning purposes a 2010 ISD has also been assumed.

INITIAL COSTING CONSIDERATIONS

No detailed project cost assessment has been conducted to date. Initial costing to date has focused on option 2b, comprising a connection between Aishihik and McIntyre substation roughly paralleling the existing L171 (80-90 km), then the Alaska highway (40 km).

At a coarse level, based solely on Yukon Energy top-down planning cost level estimates for 138 kV lines of about $130,000 per km (2005$) for all components of costs, a working cost estimate for the line is assumed to be about $15.2 million. Similarly, under the assumption that only modest revisions will be necessary to substation components at either terminus, rough initial substation project costing has been assumed to be $2.25 million. Total cost estimates have focused around $17.5 million (assumed range of $16 to $19 million, consistent with the Resource Plan section 4.3.8). Note however that reliable detailed costing for transmission line projects cannot be assessed until approximately the time of tender.

Key cost considerations for this line in comparison to “standard” Yukon 138 kV are as follows:

- Routings for all but Option 1 are largely parallel to an existing highway – 90 km for options 2a, and the Ibex Valley variations, and the entire length for options 2b and 2c.
- Except for Option 1, the line will be either within or adjacent to an existing right-of-way for 90 km of its length (options 2b, 2c, and Ibex Valley variations) or its entire length (option 2a). This may have material impacts on costs of clearing or licencing (as noted above).

Project viability in this case is very sensitive to capital cost estimates and earliest potential in-service date. The project concept today is largely a focused option to address capacity issues arising from pending retirement of 14 MW nameplate of Whitehorse diesel generation (currently being considered for between 2007 and 2011 for the various units). Under new capacity criteria for WAF, the project is expected to benefit the WAF load carrying capability by 8.2 MW to 15 MW. As primarily a reliability initiative, the economic benefits of the line go almost entirely to cost savings arising from displacing this quantity of otherwise required new diesel generation capacity.

KEY NEAR-TERM QUESTIONS TO BE ADDRESSED

The most critical planning issues to be addressed in the near term relate to the technical feasibility, scheduling and potential costs of the Project.

Although the Project is a transmission “solution” to the identified transmission constraints, as noted above there is two credible alternatives to the project:

1) by undertaking a major “life extension” project on the existing Mirrlees units; and,
2) by using expanded diesel generation at Whitehorse.

In this regard, the key initial questions go to cost and configuration in order to achieve the desired objective of reducing single point failure risk, including:

- Does elimination of redundancy practically require geographic separation that can only be gained by option 1 (Aishihik-Carmacks)? To date this has not been assumed to be required, as common cause failure for transmission lines that share rights-of-way are extremely unlikely events at the critical (winter) time periods in Yukon.
- If option 2a (Aishihik-Takhini) can provide required redundancy on L171, is it essential that YEC develop similar redundancy on the L172 connection? If so, what are the key options for achieving this? To date all assumptions are that L172 requires full N-1 redundancy consistent with L171, unless the new connection terminates at McIntyre or at S150 (which gives much the same practical effect of redundancy on L172).
- Under each of the above options, what configuration changes will be required at the respective substation to achieve desired goal?

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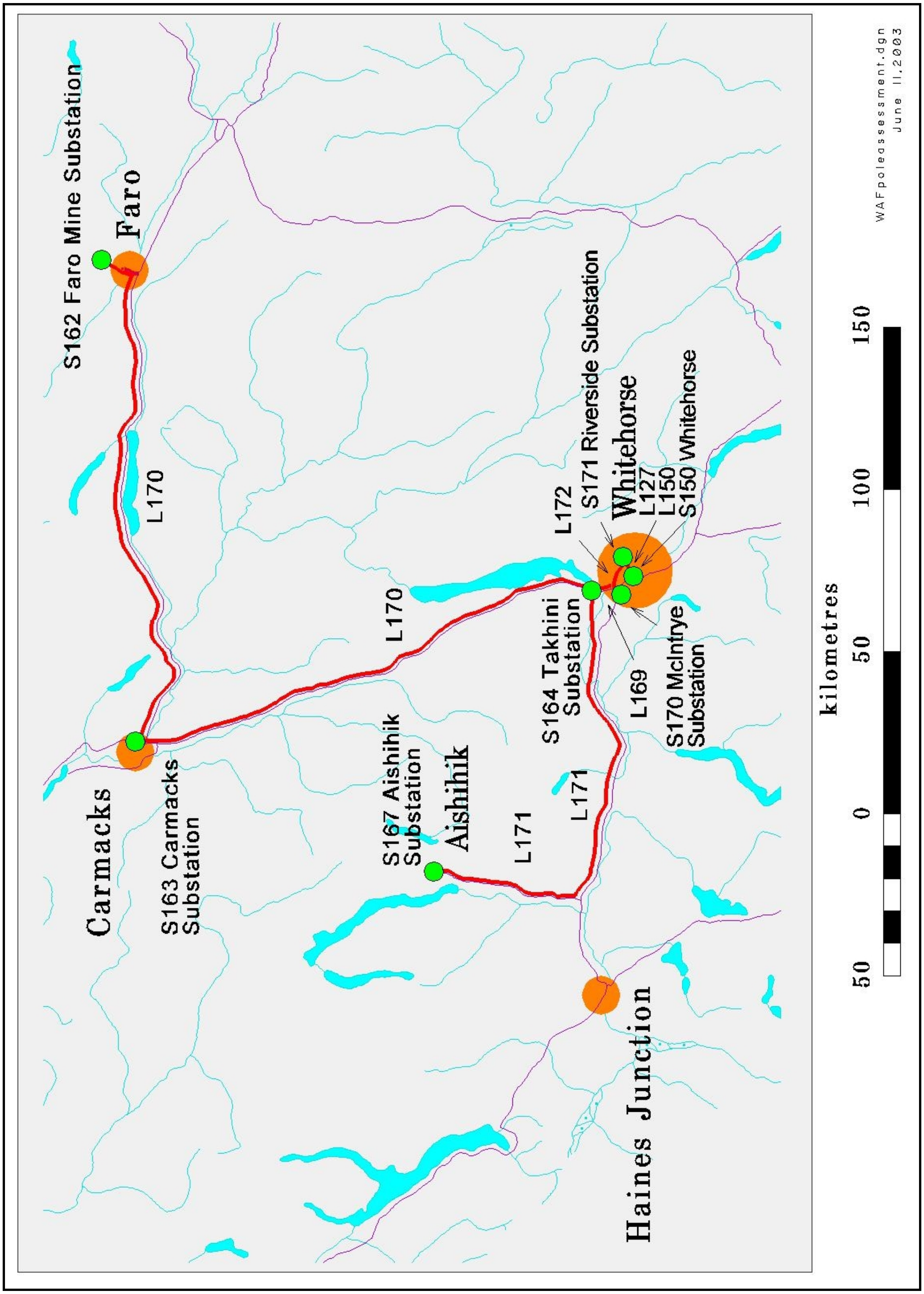
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L172
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L127
L150
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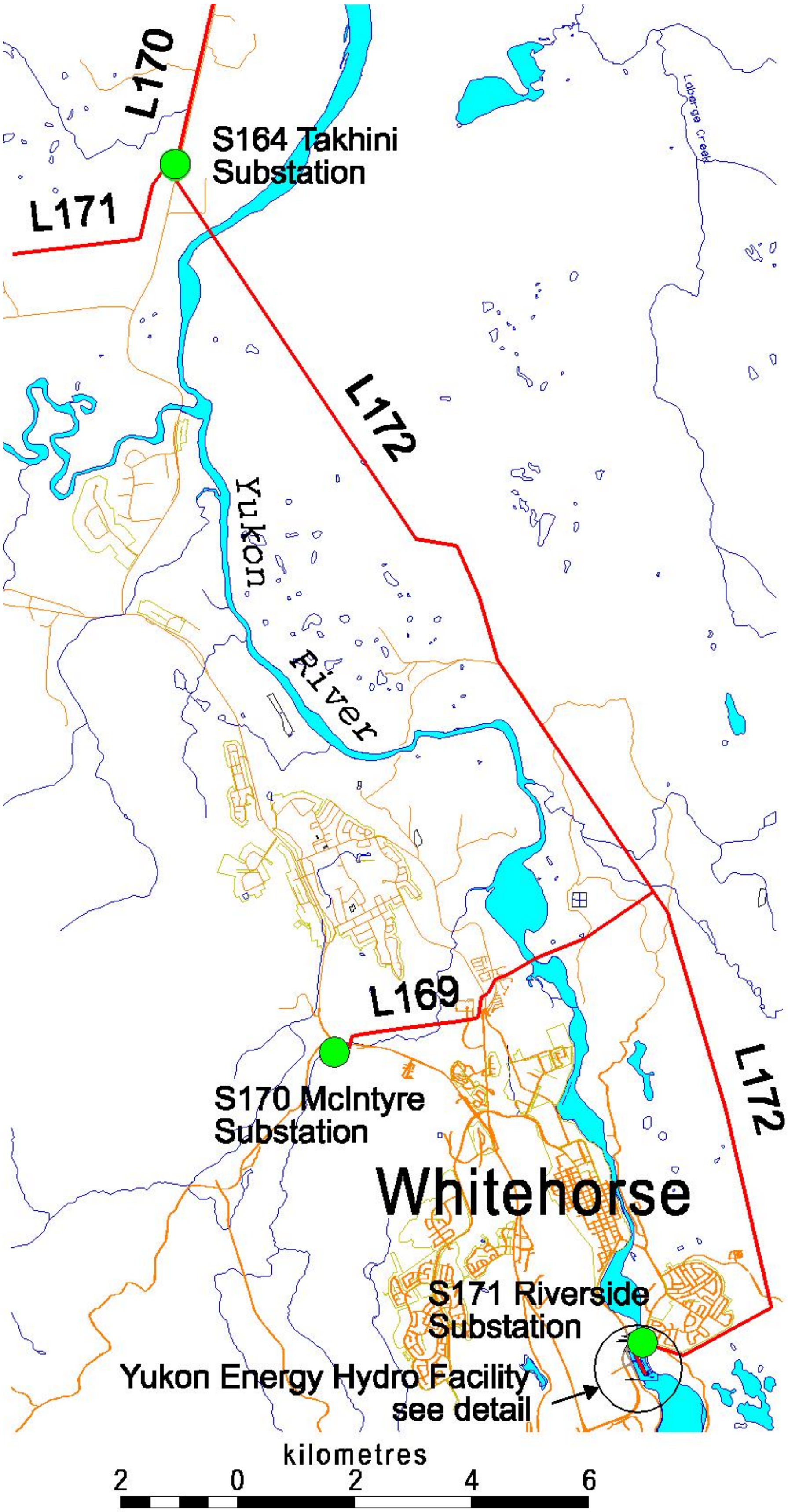
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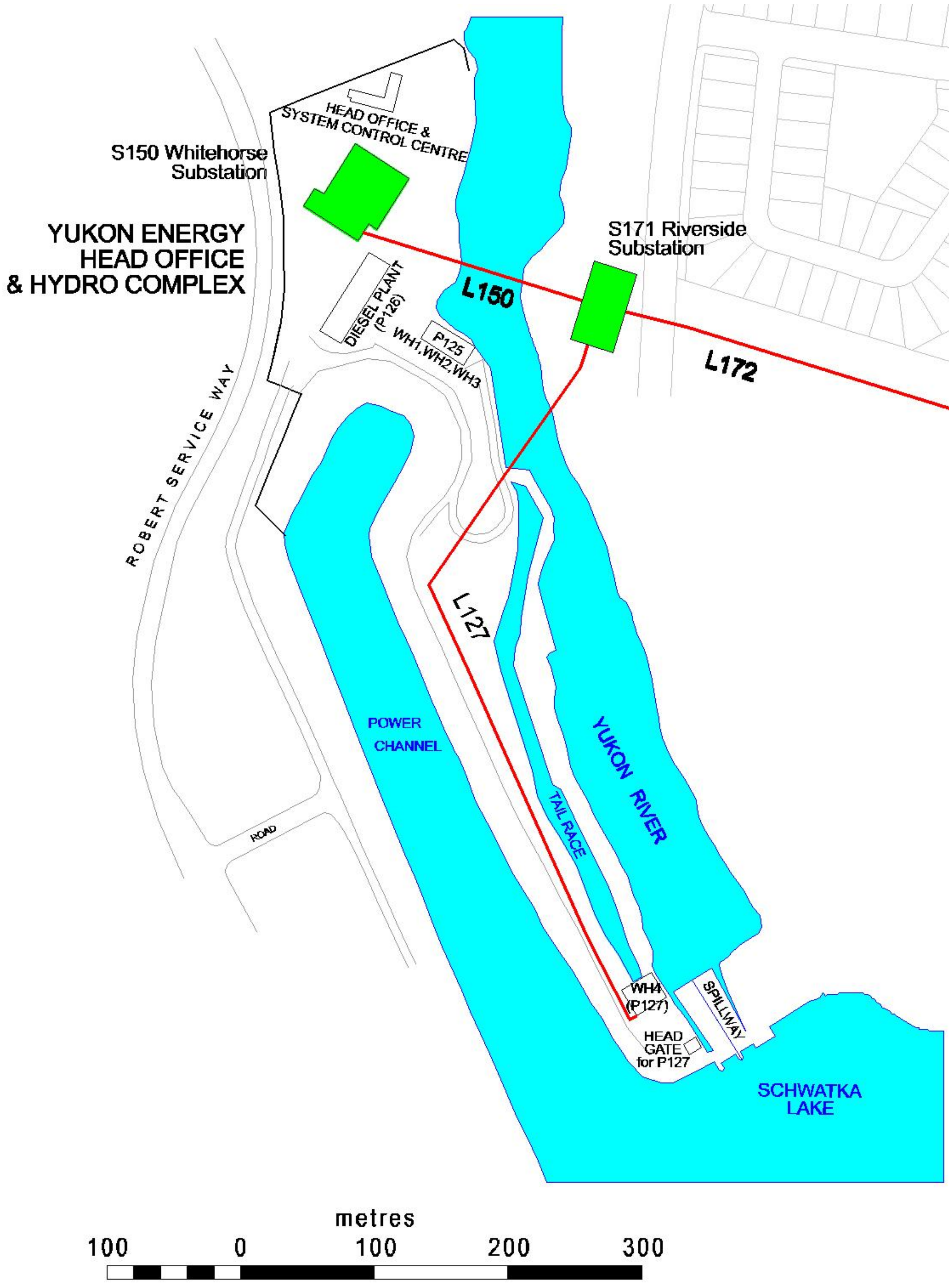
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& HYDRO COMPLEX
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(P126)
P125
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L172
ROBERT SERVICE WAY
L127
POWER
CHANNEL
YUKON RIVER
TAIL RACE
ROAD
WH4
(P127)
SPILLWAY
HEAD
GATE
for P127
SCHWATKA
LAKE
metres
100
0
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200
300

REFERENCE:

QUESTION:

The Marsh Lake Fall/Winter Storage project is credited with 1.6 MW of additional capacity from the Whitehorse Rapids Plant during the winter peak.

a) How would YEC include this project into the LOLE calculation?
b) Would the 24 MW output capacity shown on the multi-state model (on page 11 of the February 2005 Billinton/Karki Report) be simply increased to 25.6? If no, please explain.

ANSWER:

a)

Although determining exact LOLE requires sophisticated computer modeling, the LOLE on the WAF system generally changes by about 1 MW for every MW of non-Aishihik line generation that is added or retired. Since Marsh Lake Fall/Winter Storage contributes to Whitehorse Rapids generation, and is not on the Aishihik line it is projected that this project would add 1.6 MW of additional LOLE capacity.

b)

Yes.

REFERENCE:

QUESTION:

Has YEC computed the Load Carrying Capacity (LCC) at 2 days/year LOLE from 2005 to 2012 and for the projects included in Response YUB-YEC-1-10? If yes, please provide the computed LCCs.

ANSWER:

YEC assumes the question is meant to reference 2 hours/year LOLE, not 2 days/year.

Yes, YEC has computed the Load Carrying Capacity (LCC) at 2 hours/year LOLE from 2005 to 2012 in the response YUB-YEC-1-10 using an approximation approach[1]. In general, the approximation approach reflects the existing system being capable of carrying 62.9 MW[2] at an LOLE of 2 hours/year. Throughout the response to YUB-YEC-1-10, the basic load carrying capability of the WAF system is maintained at 62.9 MW, and is adjusted as follows:

- increased by all capacity increases on the WAF not dependent on the Aishihik line (e.g., at Whitehorse, Faro)
- decreased by all capacity retirements on the WAF not dependent on the Aishihik line
- increased by 0.6 MW in the cases where the Aishihik 3rd turbine is installed at 7.0 MW. This 0.6 MW value was provided by Dr. Karki as the benefit to the load carrying capability of adding the 7.0 MW unit at Aishihik.

[1] YEC does not have computer models in place to measure system specific LOLE values for various system configurations, but has used an approximation approach that reflects that basically all capacity changes on the WAF system result in a 1:1 ratio change in load carrying capability. This is confirmed for example in the Billinton report section 5 where retirement of 3 MW of diesel generation at Whitehorse results in a drop of 2.9 MW in load carrying capability (from 68.7 MW to 65.8 MW at a consistent LOLE of 1.2 hours/year).

[2] The 62.9 MW benchmark is based on the values shown in Figure 4.4 of the February 2005 Billinton/Karki report plus 0.4 MW for Fish Lake firm capacity less 0.4 MW for the Haines Junction diesel (at the time data was provided to the authors for the Billinton/Karki report YEC had been assuming the Haines Junction unit was capable of 1.7 MW; since that time, YEC has confirmed that this is 1.3 MW unit.

REFERENCE:

QUESTION:

The Carmacks-Stewart transmission line would join the MD and WAF grids into one larger grid, which means that generation and load data for the MD grid is required in order to compute the LCC (at 2 days/year LOLE) of the joined MD-WAF grids after this transmission line is commissioned. Therefore, please provide the following data:

a) Chronological hourly loads for the MD Grid (similar to that provided in YUB-YEC-1-3 Attachment 3B).
b) A list of all MD generating units complete with name, type, FOR, and seasonal limitations. (Unless the list in Table 2.1 of the Resource Plan is comprehensive, the FORs are 3% for hydro and 10% for diesel, and there are no energy or capacity limitations.)

ANSWER:

YEC assumes the question is meant to reference 2 hours/year LOLE, not 2 days/year.

a)

The Mayo Dawson transmission line was put into service in Sept 2003. The attached Microsoft Excel file YUB-YEC-2-14 Attachment 1 contains hourly generation from the Mayo Hydro Plant and not exclusively the load on the M/D transmission line (includes both Mayo and Dawson, excluding any periods of diesel generation). The Mayo Hydro Plant provides power to three feeders, town of Mayo, Elsa, and Dawson.

b)

The list in table 2.1 of the Resource Plan is comprehensive and the FORs are as stated above. There are no energy or capacity seasonal limitations.

REFERENCE: Review of the Capital Resource Plans of Yukon Energy Corporation and Yukon Electrical Company Limited. Report to Commissioner in Executive Council by Yukon by Yukon Utilities Board, December 7, 1992.

QUESTION:

Pages 82 to 83 discuss a study of ice conditions and field testing of a plan that included load factoring. The study could result in a formalized plan that may result in an adjustment to the firm capacity of the Whitehorse Rapids Plant.

a) Did the aforementioned study result in a change in the rated capacity for Whitehorse Rapids? Is there any further opportunity for load factoring?
b) Please provide a copy and the results of the study.

ANSWER:

a)

The study did not lead to a change in the firm capacity of the Whitehorse Rapids plant in winter.

The firm capacity of the Whitehorse Rapids has been adjusted since 1992 from 19 MW to 24 MW[1], with the key constraint continuing to be the limits on water availability (storage) at Marsh Lake, and to a lesser degree inability to use the plant for major peaking use due to lack of ability to dispatch Marsh Lake in this fashion (as well as downstream ice constraints)[2]. Also see YUB-YEC-2-8.

Yukon Energy continues to pursue the potential ability for increased "load factoring"; however, the plant is already load factored basically to the limits of its existing configuration. To increase load factoring further, two major obstacles must be satisfactorily resolved:

[1] "…In 1992, the Companies indicated that in drought years, if 24 MW of plant capacity was required, up to 5 MW of diesel may be able to be temporarily leased for the winter to maintain a 24 MW reliable level of capacity at this plant…As a result, since that time the hydro units at this plant have been assigned a winter reliable capacity rating of 24 MW" (Resource Plan pg 3-8)

[2] The limitations reflect both physical capability of the system to be operated in this fashion, as well as risks that arise with respect to ice and flooding, particularly in Whitehorse.

1. Several gates at Lewes Dam (Marsh Lake) must be automated and capable of cold weather operation to allow for control over a daily period.
2. Further ice studies are required to confirm that this will not result in flooding of Whitehorse or other related ice issues (including potential ice issues upstream of the generating station). The study attached in part (b) of this question confirmed ice-related limits on varying the water flows on the Yukon River given the degree of berming and development in low lying areas (particularly Marwell) at that time. Further work is now underway to determine whether physical work in the affected areas (such as increased berming of low lying properties) or mitigative measures by YEC (such as increased berming or other property protection might allow for increased load factoring at the Whitehorse Rapids plant). These studies will not be completed for some time, as they must ultimately test flow conditions and ice response over winter seasons.

(b)

See attached (YUB-YEC-2-15 Attachment 1).

Yukon Energy Corporation
and
The Yukon Electrical Company Limited

Study of Whitehorse Rapids Generating Station Operations with an Ice Cover on the Yukon River

Final

September 1995
P10618.02

Prepared by
Acres International Limited
Suite 500, 10201 Southport Road S.W.
Calgary, Alberta
T2W 4X9

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1 Introduction

1 Introduction

1.1 Background

Historically, Whitehorse has been prone to major flooding due to the rise in water levels as the ice cover forms on the Yukon River. This threat has largely been eliminated with the construction of the Whitehorse Rapids Generating Station and Marsh Lake Control Structure. These structures control the winter flows which result in the reduction of the supply of ice from upriver. These facilities are owned by Yukon Energy Corporation (YEC) and managed by Yukon Electrical Company Limited (YECL). Nevertheless, ice cover formation still causes the water level to rise each year. This can lead to flooding in low lying areas of the city, unless restrictions are imposed on the winter operation of the station.

Prior to the present studies, the restrictions on Whitehorse Rapids Generating Station were developed over time, based on the experience and judgment of engineering management and operating personnel. During the critical ice cover formation period the station was held at a uniform daily discharge (170 m^3/s was the maximum achieved), with a slight variation in discharge of $\pm$ 10 per cent to provide some daily peaking.

After the ice cover had formed and the water levels dropped, due to smoothing of the ice cover, the daily discharge was increased. The maximum flow that had been demonstrated to avoid flooding was 200 m^3/s. This is considerably less than the station discharge capacity of 276 m^3/s.

During the driest year of record, the average daily discharge during the winter months would only be 127 m^3/s. This flow would give an average generation of 19 MW, approximately one half of the station capacity. Allowing peaking of only 10 percent above the average daily discharge would severely restrict the power output of the generating station. Based on experience at other hydroelectric stations on ice covered rivers it was believed that restricting the peaking to only 10 percent of the average was excessively conservative. This initiated a study of the ice cover effects on the Yukon River at Whitehorse.

This study has included an engineering analysis using a computer model and confirming field tests on the Yukon River. Acres report "Ice Study of the Yukon River Downstream of Whitehorse Rapids Generating Station" dated February 1994, covers the model analysis. Acres reports "Ice Study Field Observations and Tests on the Yukon River", dated April 1994, and "Field Test During Ice Cover Formation Winter of 1994/1995", dated June 1995, describe the field tests which were carried out during the winters of 1993/1994 and 1994/1995 respectively.

This final report concludes the study. In Section 2 of this report the findings of the engineering analysis and field tests are summarized and some of the figures from the previous reports are reproduced here with corrections to the bankfull levels. Section 3 covers the study conclusions, and Section 4 presents recommendations for future operation of Whitehorse Rapids Generating Station.

1.2 Objectives of the Ice Study

The main objectives of the ice study were to derive operating practices which would determine:

- the maximum allowable average daily winter flow through the station; and

- the maximum allowable amount of within-day peaking at the station.

Neither objective can be permitted to increase the risk of flooding the low lying areas of Whitehorse.

The first task of this study was to develop a reliable model to predict the effects of different operating practices on the ice cover and water levels on the Yukon River. Acres ICESIM computer model was chosen as the best available model to analyze the river before performing field tests. This model would give reasonable estimates of the range of flows that could be safely released. As well, the modeling allowed the determination of flood levels in the event of ice breakup, thereby providing an assessment of the risk involved in increasing the river flows.

After the model analysis, a series of field tests were performed to confirm the model predictions. Two different times were chosen for the tests so that the ice conditions during formation and after formation could be investigated.

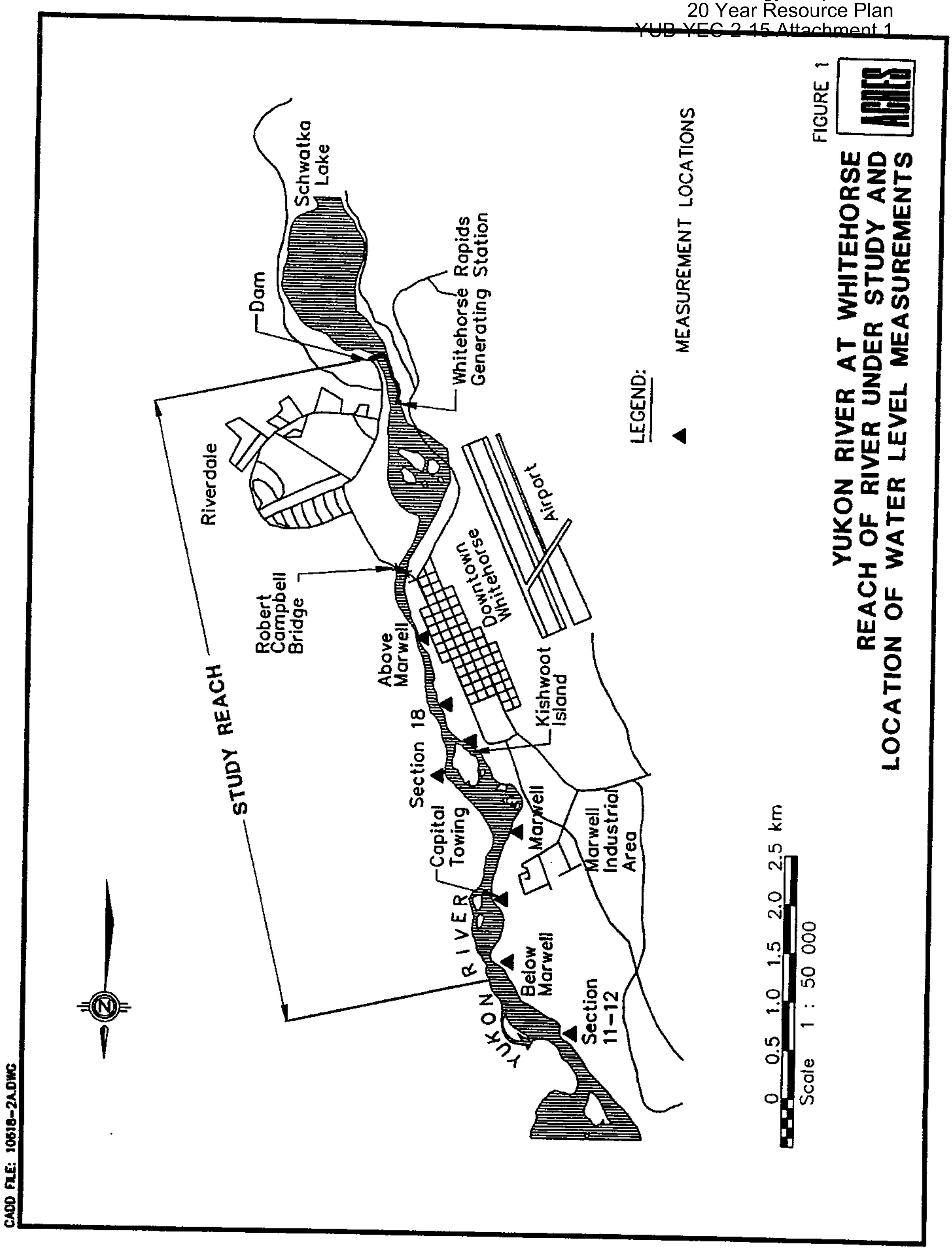
1.3 Site Description

The Whitehorse Rapids Generating Station is located on the Yukon River approximately 1.5 km upstream of Whitehorse, Yukon. During the winter the flow in the river is regulated by the Marsh Lake Control Structure which is about 35 km upstream of the hydroelectric plant. Marsh Lake provides storage for the hydroelectric plant operation during the winter. The water flow records show that, on average, a release of 162 m^3/s during the winter months of November through April can be maintained with proper operation of the Marsh Lake Control Structure. The records also show that the range in average winter release could vary from 127 m^3/s to 195 m^3/s. Discharge measurement of the river flow is performed at Whitehorse Rapids using rating curves for the generating units and spillway gates. Discharge rating curves for the Marsh Lake Control Structure are not available.

The small forebay formed by the Whitehorse Rapids Dam, Schwatka Lake, has an operating range of 1.067 m and can provide daily storage for peaking operations. However, drawing the reservoir down reduces energy generation, and is avoided whenever possible. Presently, the electrical system can operate with minimal peaking from the Whitehorse Rapids Generating Station. However, future increases in electrical load will increase the demand for peaking power from this plant.

The Yukon River through Whitehorse has a fairly steep gradient, falling 4 m in a 6 km reach. The flow velocities in this reach range from 1 to 1.5 m/s. This results in the relatively large increases in water level when the ice cover forms on the Yukon River. Figure 1 shows the reach of river under study and the observation point locations used to monitor the ice formation and water levels.

On average, Whitehorse receives 2100 degree-days of freezing. The temperature in January normally ranges from a daily minimum of -25°C to a daily maximum of -16°C. However, minimum temperatures of -45°C or colder occur occasionally during severe cold periods, the extreme minimum temperature recorded at Whitehorse is -52°C.


Schwatka Lake
Dam
Whitehorse Rapids Generating Station
Riverdale
Airport
Robert Campbell Bridge
Downtown Whitehorse
Above Marwell
Kishwoot Island
Section 18
Marwell
Marwell Industrial Area
Capital Towing
YUKON RIVER
Below Marwell
Section 11-12
STUDY REACH
LEGEND:
MEASUREMENT LOCATIONS
0 0.5 1.0 1.5 2.0 2.5 km
Scale 1 : 50 000
FIGURE 1
YUKON RIVER AT WHITEHORSE
REACH OF RIVER UNDER STUDY AND
LOCATION OF WATER LEVEL MEASUREMENTS
CADD FILE: 10618-2A.DWG

2 Summary of Computer Model Analysis and Field Tests

2 Summary of Computer Model Analysis and Field Tests

The model analysis and the field tests conducted in the study have shown that the winter power capacity of the Whitehorse Rapids Generating Station can be safely increased above what is presently being used. The plant can be relied on to provide more peaking power and thus offset some future purchases of standby peaking units. The findings of the model analysis and field tests are summarized below.

2.1 River Ice Model Analysis

The computer model analysis of the ice cover formation was done for a range of average daily discharges from 130 m^3/s to 200 m^3/s. These simulations also included a prediction of the water levels at a peaking discharge of 200 m^3/s. The results of the analysis are shown in Figures 2.1 to 2.3. The figures show the maximum water levels that would occur along the study reach during formation of the ice cover. Water levels for the mean daily flow and the peaking flow are both shown on the figures.

It is apparent in Figure 2.1, that at an average daily discharge of 130 m^3/s the station may be able to peak up to 200 m^3/s without flooding the low lying areas. This peaking would cause 0.8 m of fluctuation in the water levels, ± 0.4 m around the mean levels at 130 m^3/s. This amount of fluctuation in water level could disturb the ice cover and thus this amount of peaking should be approached with caution. The allowable magnitude of peaking depends on the elevation of the shorefast ice. Peaking should never be increased to the point where the river ice cover looses contact with the shorefast ice that holds the ice cover in place.

These results of the ice analysis indicate that the highest average daily discharge allowable during formation of the ice cover is approximately 170 m^3/s (Figure 2.2). The water levels in the Marwell area are just below the bankfull level. This is in agreement with historical observations and the observations made in the winter of 1993/1994 where the average discharge was 167 m^3/s while the ice front was advancing through the Marwell area.

Peaking will be limited by the average discharge and also by the position of the ice front. As the ice front progresses upstream through the Marwell area, peaking may not be possible when the average discharge exceeds 170 m^3/s.

Figure 2.3 shows the maximum water levels during formation at 200 m^3/s and the water levels after the ice cover has smoothed. Smoothing of the ice cover takes 4 to 6 weeks depending on the roughness of the cover at formation, a rougher cover will take longer to smooth out. The water levels during formation show that the Marwell area would be flooded if the cover was formed at 200 m^3/s. It is also possible that these water levels would occur if the ice cover was disturbed from that formed at a lower flow (e.g. 130 m^3/s) and then reformed at a peaking flow of 200 m^3/s.

2.2 Field Program March 1994

This first test program had tentatively planned for four tests during the week of March 7, 1994. The tests were designed to evaluate the ability to increase the power output from the Whitehorse Rapids Generating Station for base load and peaking requirements in the latter part of winter. The tests were run with a constant inflow to the forebay. The additional water required for the test flows was taken out of storage in the forebay.

During each test, the water levels and the response of the ice cover was monitored constantly. Water levels were measured using standard survey methods and the events were recorded on still and video cameras. After each test the results were analyzed to determine if it was safe to proceed with the next test.

The four tests were to be run with peak discharges of 200, 220, and 240 m^3/s with durations of 2 to 6 hours. The test at 240 m^3/s was canceled due to uncertainty with the ice cover conditions upstream of Robert Campbell Bridge. The water level measurements from the tests are shown in Figures 2.4 to 2.6.

The response of the river to the increase in discharge can be seen in Figure 2.4. As the discharge increases and decreases the water levels rise and fall respectively. At the Capital Towing area it takes a little over two hours for the water level to stabilize.

From the river profiles in Figures 2.5 and 2.6 it is evident that the smoothing of the ice cover has a large effect on the water levels. Comparing the measured water levels in Figure 2.5 with the predicted water levels in Figure 2.3 it can be seen that there is large difference between the predicted levels after smoothing and the measured levels. This difference can result from two conditions:

- the ice is smoother than what was assumed in the model; a value of 0.05 to 0.08 was used for Mannings-n of the ice at the time of formation, reducing to a value of 0.01 after 45 days.

- the ice is thinner than what the model predicted due to erosion of the ice after the ice cover formed; the model predicted ice thicknesses of 1 to 2 m while measured ice thicknesses during the test were only from 0.3 to 0.6 m.

Thus it is apparent that the model is overly conservative in predicting the water levels after long periods of smoothing. This is not a major concern since the peak water levels at formation and the levels shortly after formation are the most important for operation of the hydroelectric station.

Figure 2.6 shows that the water is well below the bankfull level even at 220 m^3/s. Based on the water levels downstream of Robert Campbell Bridge at 200 and 220 m^3/s it was evident that the discharge could have been increased to 240 m^3/s without causing any deterioration of the downstream ice cover. However, the ice cover upstream of the bridge was not responding to the increase in water level and a large amount of water was flowing on top of the ice at 220 m^3/s. At 240 m^3/s, a larger area of ice would be inundated with water flow on top of the ice. Normally, during the winter this would not pose a problem. But due to the fact that the tests were being performed after a period of above 0°C temperatures, with possible weakening of the ice cover, it was deemed unnecessary to conduct the test and risk lifting the ice cover upstream of the bridge.

From these tests it was determined that relatively large increases in discharge are possible after the ice cover has smoothed. The amount of increase will be dependent on the ice conditions at the time.

2.3 Field Program November 1994

This test was performed during ice cover formation on the Yukon River. The test had two objectives. The first was to determine if the water levels that occur with peaking operations are lower than the water levels with a steady discharge equal to the peak flow rate. The second objective was to determine the peaking capability of the Whitehorse Rapids Generating Station during the ice cover formation period. Figure 2.7 shows the hourly discharges that were released from the station during the test.

2.3.1 Difference in Water Levels Between Peaking and Steady Flows

Figures 2.8 and 2.9 show the water levels during the low flow and high flow periods during the test. To evaluate the difference in water levels with peaking operations versus a steady river discharge, a comparison is made between the water levels during ice cover formation in 1993 and 1994. While the ice cover was forming around Kishwoot

Island in 1993, with a fairly steady discharge of 173 m^3/s, the maximum recorded water level at the Kishwoot Island observation point was 632.21 m. In 1994, with an average discharge of 150 m^3/s, the maximum recorded water level was 632.00 m at a peak discharge of 180 m^3/s. The ICESIM model predicted that the water level would be 631.97 m with peaking operations and as high as 632.5 m with a steady discharge of 180 m^3/s. This confirms that the Yukon River shows the same phenomenon as larger rivers where the water levels during peak flows are less than the water levels at the same steady state discharge.

2.3.2 Peaking Capability During Ice Cover Formation

During ice cover formation, a peak discharge of 185 m^3/s appears to be possible for average flow rates of 150 to 160 m^3/s, producing a 0.5 m fluctuation in water level. Having this level of peaking capability at the Whitehorse station during the high load hours of the day will increase the hydro capacity of WAF system. Applying this level of peaking in the historic low flow year of 127 m^3/s would allow a peak discharge of 175 m^3/s. Further monitoring of the water levels during the ice cover formation period would allow a better prediction of the capabilities of the plant during a low flow year. The maximum average daily discharge during ice cover formation at the low-lying areas in Whitehorse appears to be 170 m^3/s. At this average discharge, the allowable peak discharge will be equal to or less than the 185 m^3/s demonstrated in the November 1994 test. Further monitoring of the water levels during ice cover formation at high flows would allow better prediction of the capabilities of the plant during a high flow year.

The best method of monitoring the water levels at the low-lying areas would be installing water level recorders and transmitters to allow the plant operators to continuously monitor the water levels. This would also allow the operators to react quickly to any problems that may occur during the peak flow periods.

Figure 2.1
Water Levels for Ice Cover Formation at 130 m³/s with Peaking of 200 m³/s

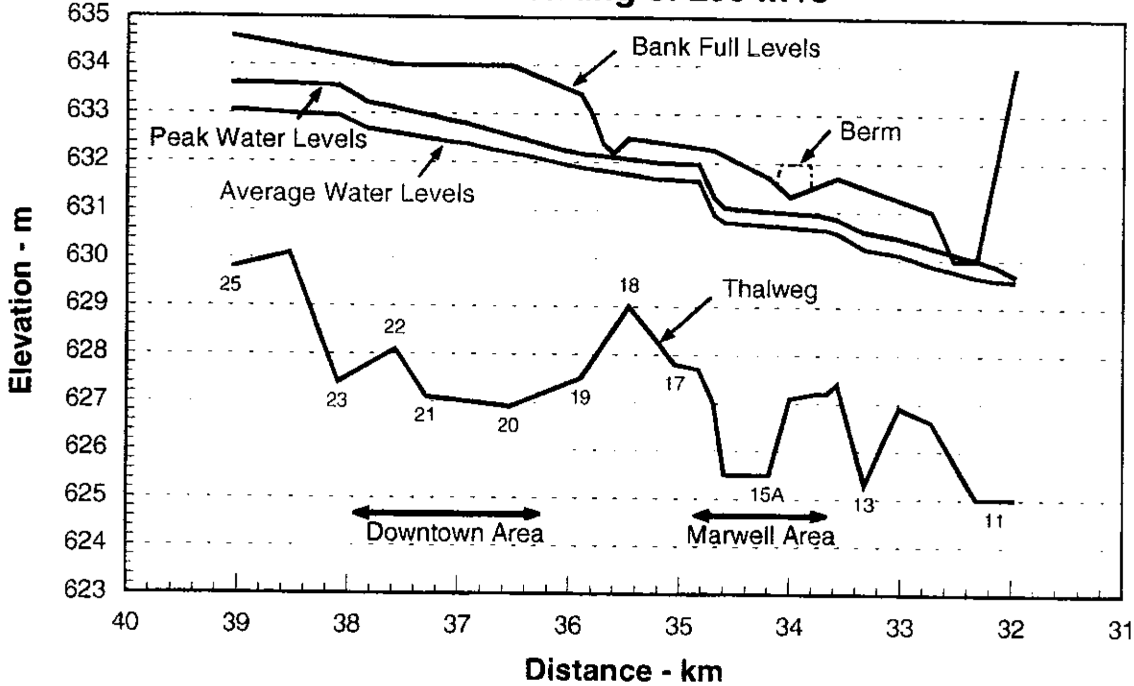


Figure 2.2
Water Levels for Ice Cover Formation at 170 m³/s with Peaking of 200 m³/s

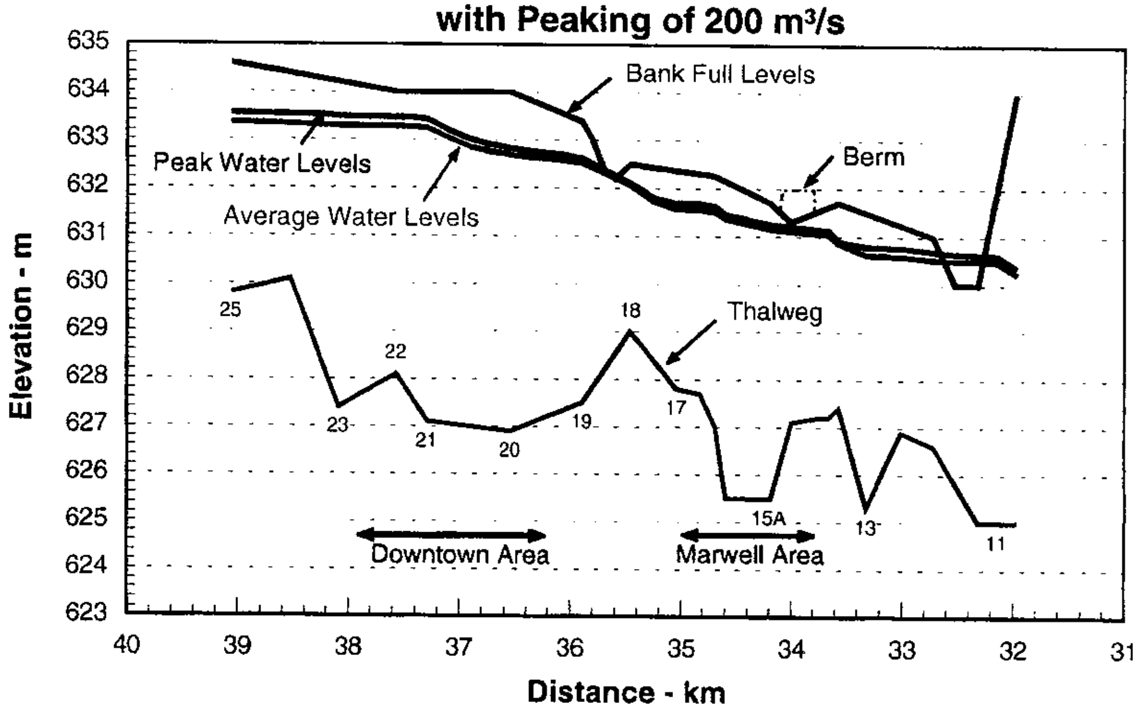


Figure 2.3
Water Levels for Ice Cover Formation at 200 m³/s

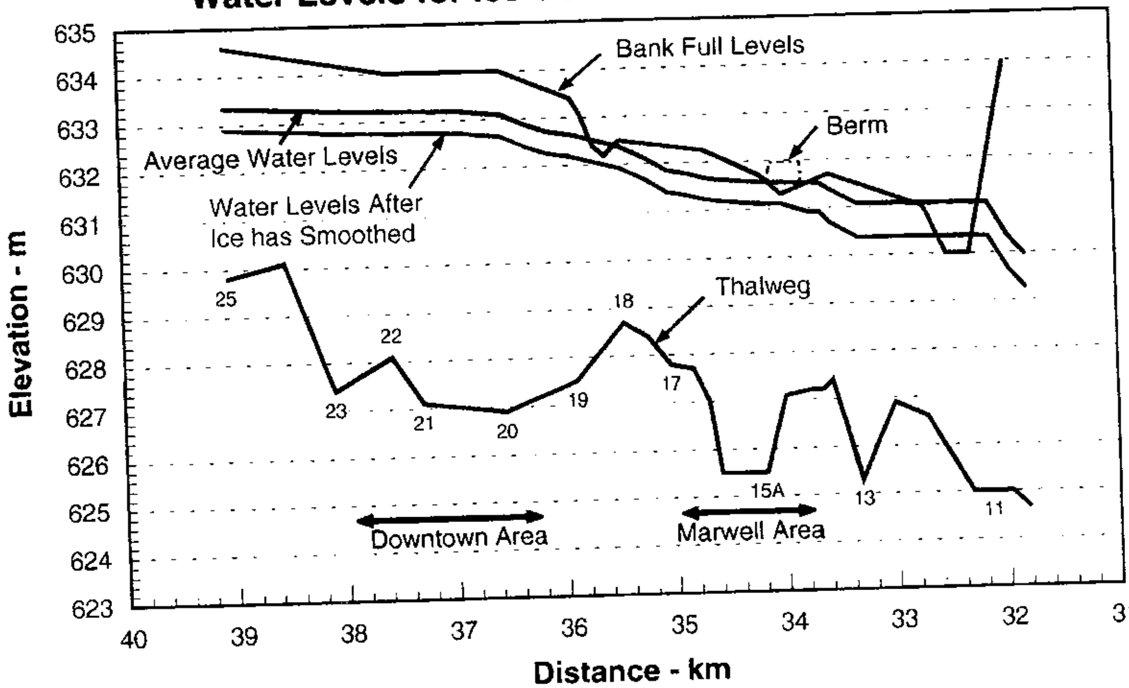


Figure 2.4
Water Levels During Test on March 9, 1994
Peak Discharge 200 m³/s

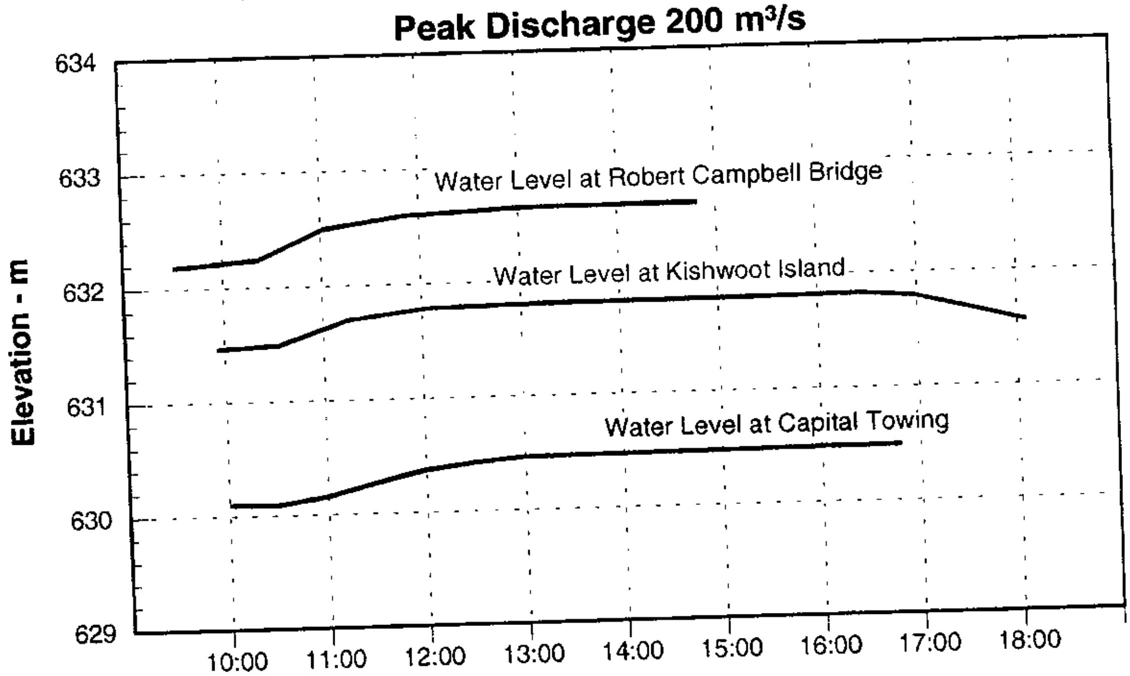


Figure 2.5
Water Level Profile During Test on March 9, 1994
Peak Discharge 200 m³/s

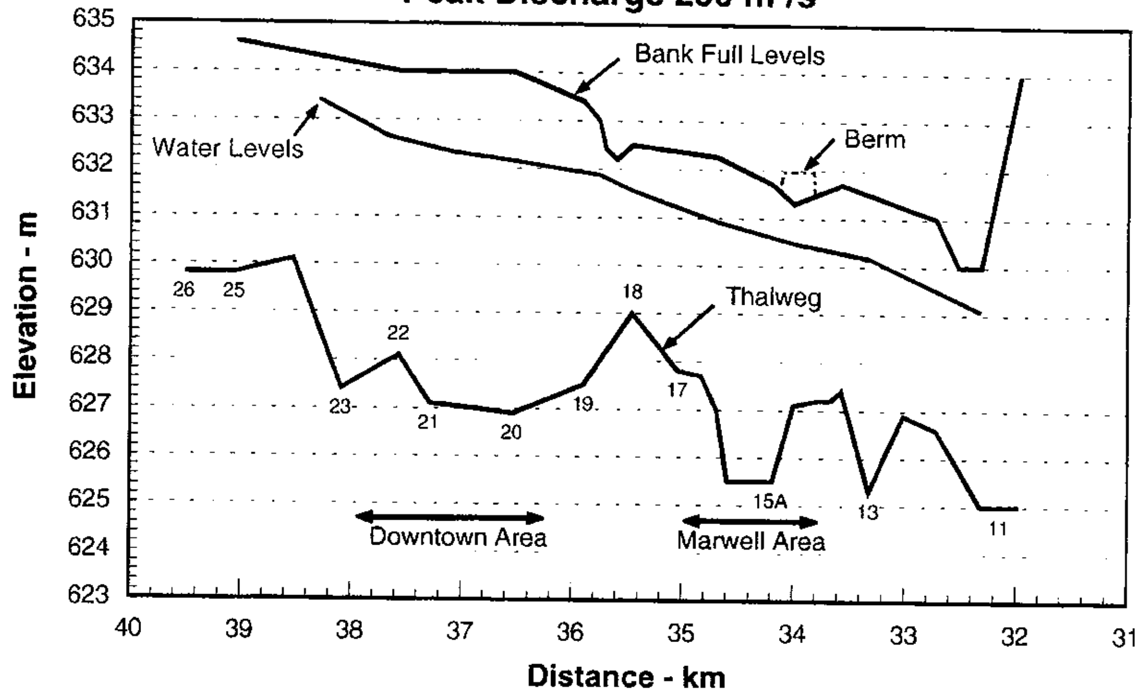


Figure 2.6
Water Level Profile During Test on March 10, 1994
Peak Discharge 220 m³/s

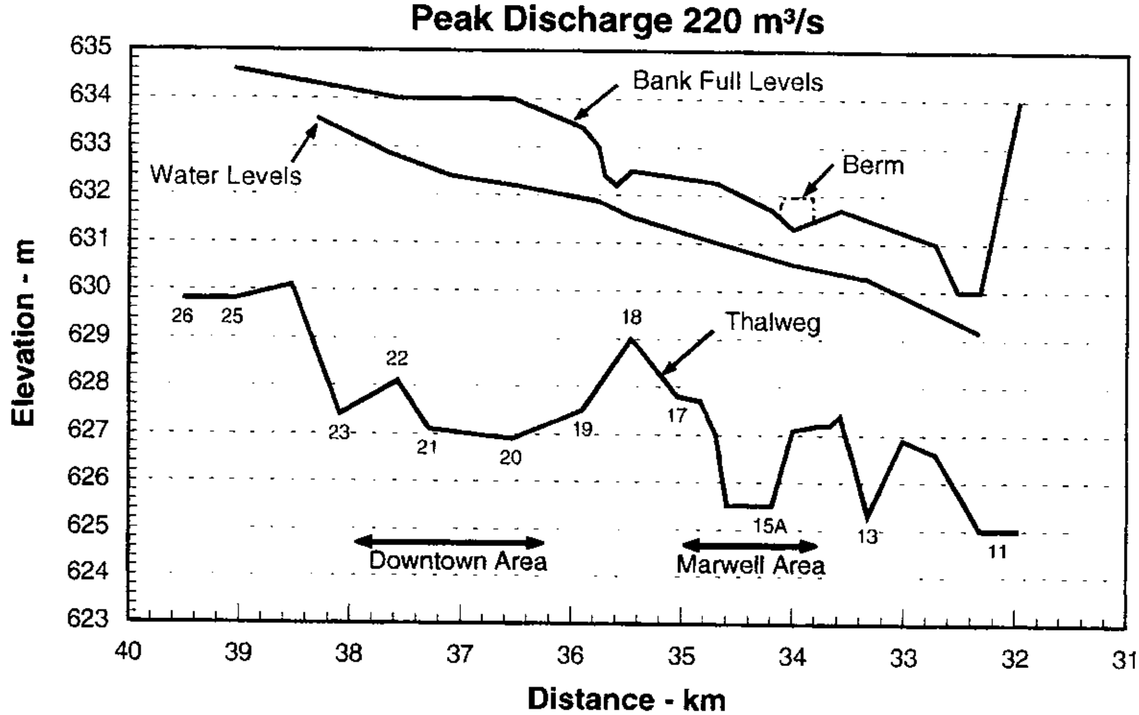
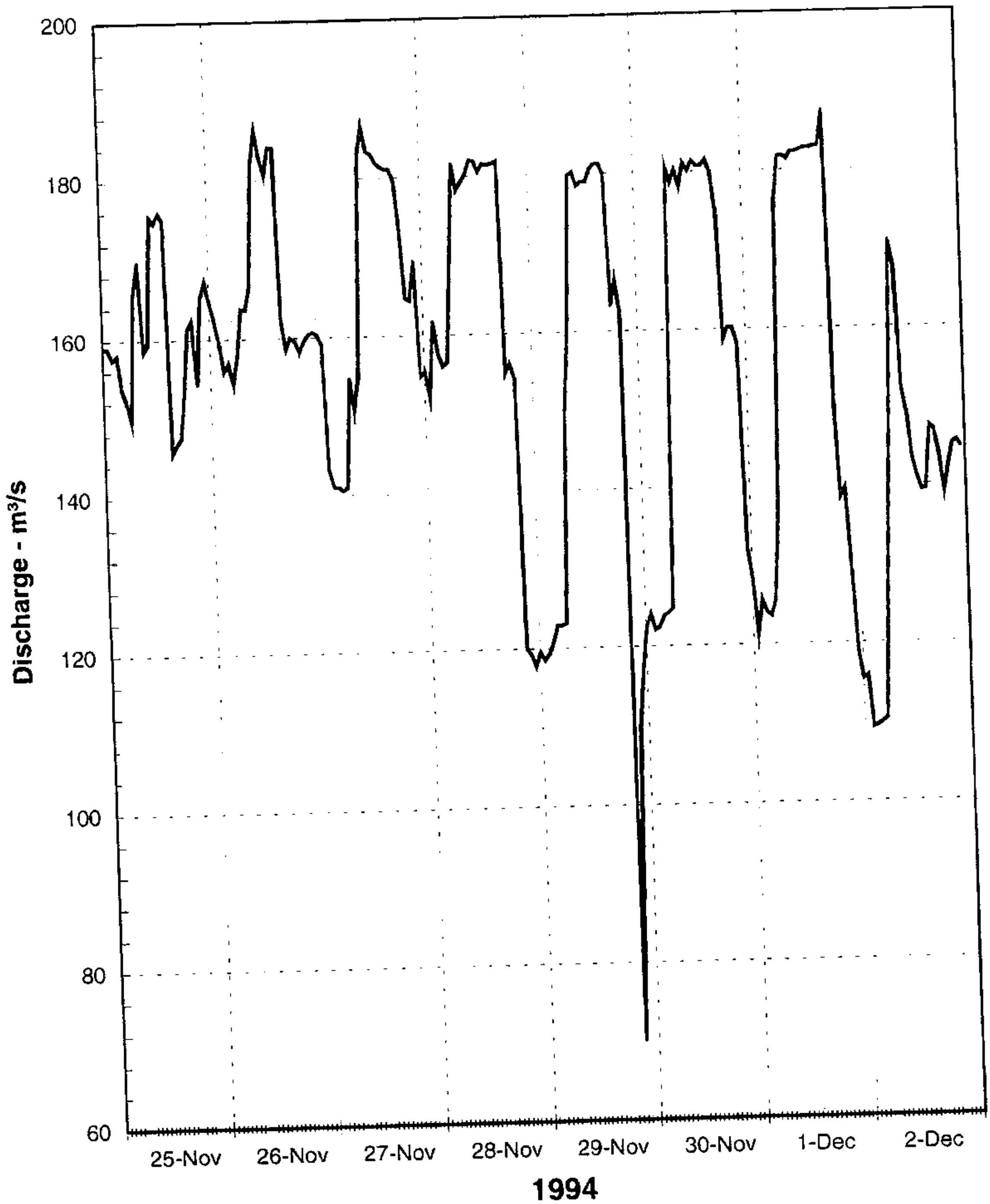


Figure 2.7
Yukon River Hourly Discharge



(P10618.02) Acres International Limited

Figure 2.8
Water Level Profiles for Low Flows

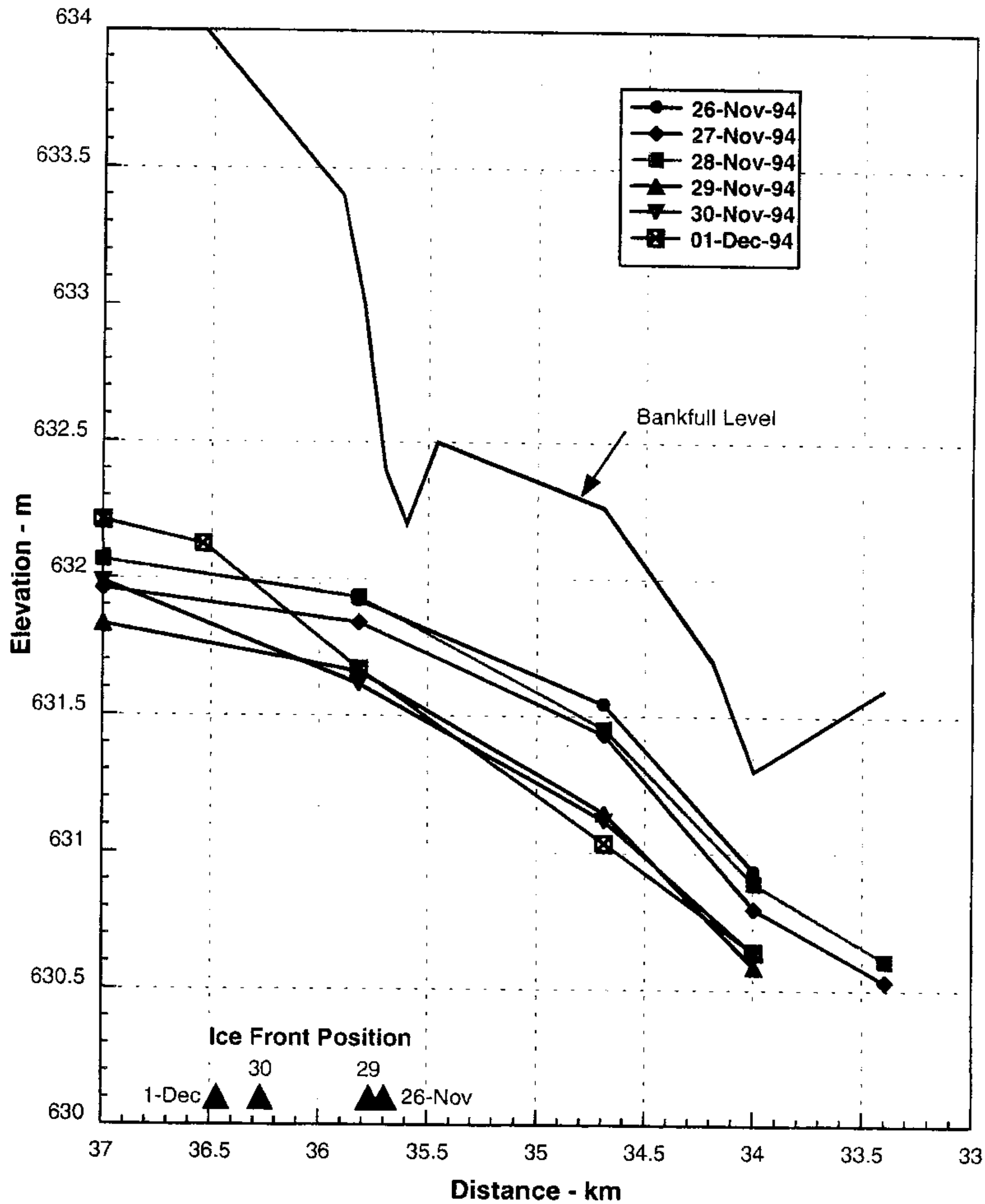
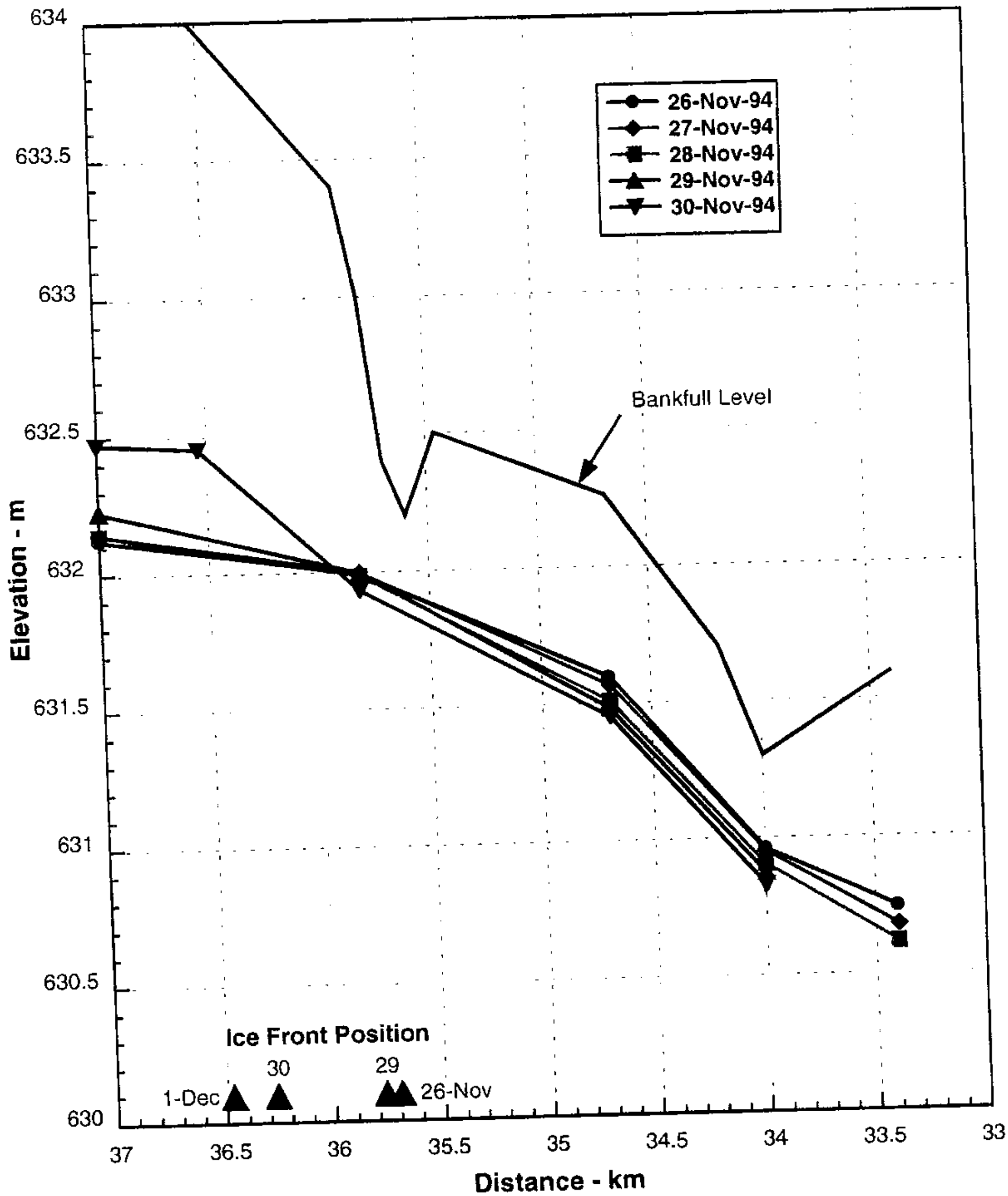


Figure 2.9
Water Level Profiles for High Flows



(P10618.02) Acres International Limited

3 Conclusions

3 Conclusions

This study has shown that the reliable peak power capacity of the Whitehorse Rapids Generating Station can be increased. The engineering analysis and field tests have shown that moderate daily peaking operations are possible without risk of flooding the low lying areas in Whitehorse.

The field tests conducted in March, 1994 proved that the discharge can be increased substantially after the ice cover has formed and the underside of the ice has smoothed. The amount of increase will depend on the ice conditions from year to year. The conditions which would limit the increase are:

- The degree of smoothing that occurs to the underside of the ice cover.
- The ice cover is free to move up and down with the change in water levels and the water does not flow freely on top of the ice.
- The floating ice cover must not be raised above the shorefast ice.
- The ice cover must remain intact when the discharge is increased and not show any signs of traverse cracking which indicates potential breakup.

The test program conducted during November, 1994 proved that relatively large fluctuations in power output from the Whitehorse hydroelectric station are possible on a daily basis during formation of the ice cover on the Yukon River through Whitehorse. The test also showed that the water levels during periods of peaking are less than what would occur if the ice cover formed at a constant discharge equal to the peak flow. This is only true for daily flow fluctuations. Weekly or monthly fluctuations would not show the same results.

Given the current conditions along the banks of the Yukon River in Whitehorse the maximum daily peak discharge while the ice cover is forming in the low lying areas would be 185 m^3/s when the average daily discharge is between 150 and 160 m^3/s. At higher average discharges, higher water levels, may preclude peaking operations.

Conversely, the ICESIM model predicts that higher peak discharges may be possible at lower average discharges but this can only be proven with further observations by YEC/YECL. The field tests have shown that at the historic low flow of 127 m^3/s a peak discharge of 175 m^3/s can easily be achieved.

4 Recommendations

4 Recommendations

Caution is advised in trying to increase the discharge beyond what has been proven in the field tests without proper monitoring of the river water levels. Peaking operations on some rivers have caused the ice cover to collapse and form again at the higher discharge resulting in high water levels and potential flooding. One reason for this to occur would be peaking the flow too high and causing the floating ice in the center of the river to lift above the shorefast ice. Without restraint from the sides, the ice cover is free to move and shove under the forces of the higher discharge.

The operating practices to be exercised each year will be dependent on the amount of water available for release over the winter months. In very wet years, there may be too much water to perform any peaking operations and thus a steady release from the station is recommended. In the years when the average release will be greater than 170 m^3/s it is recommended that the flow during the ice formation period be restricted to avoid flooding in Whitehorse. Once the ice cover begins to smooth, usually 2 to 4 weeks, the discharge can be increased gradually. The testing to date has shown that an average daily discharge of 200 m^3/s is achievable once the ice cover has completely smoothed.

In average years an economic balance will need to be determined between peaking operations and loss of energy from drawing the forebay level down. In dry years peaking operations may be required to meet the load demands of the electrical system.

The area that is at the most risk of flooding is the 200 m stretch along the west bank adjacent to Kishwoot Island. Raising this area by 1.0 m would allow an increase in river discharge during ice cover formation. However, this would require temporarily moving 6 to 10 trailers/shacks in this area while the work is done and then placing them back on the higher ground.

Further caution is advised during the spring melt period. When the ice cover begins to weaken, peaking operations should be restricted to avoid premature breakup of the ice cover.

Automatic water level recorders with transmitters should be installed at the low lying areas in Whitehorse. This will allow the plant operators to monitor the water levels and observe how the levels are affected by the operations at the Whitehorse plant. As well, monitoring the water levels will allow the plant operators to respond quickly to any problems that may occur with unexpected high water levels.

Drawing the reservoir down to supply the water for peak flows is presently the best method available. However, this decreases the energy generation of the plant due to the loss of head. In the future, the peak flows could be partially supplied by increasing the discharge from Marsh Lake. By fluctuating the hourly discharge from Marsh Lake the drawdown of Schwatka Lake can be reduced. However, this would require automation of the gates at the Marsh Lake Control Structure. These improvements would not preclude the need to maintain average daily flows less than 170 m^3/s during the ice formation period.

It is recommended that a system planning study should be done to determine the benefits of peaking the Whitehorse Rapids Generating Station. The study should look at the value of peaking capacity versus the cost of drawing the forebay down. This study should also look at the benefits of supplying the peak flows from Marsh Lake versus the costs of making the necessary improvements at the Marsh Lake Control Structure.

REFERENCE: **Review of the Capital Resource Plans of Yukon Energy Corporation and Yukon Electrical Company Limited. Report to Commissioner in Executive Council by Yukon by Yukon Utilities Board, December 7, 1992. (Page 86, 7.3.1.2 Reserve Criteria)**

QUESTION:

The Board notes Mr. Druce's comment that the Yukon System is not an interconnected system and, thus, has the ability to develop its own reliability criteria specific to Yukon and the importance of using reliability criteria that result in a reliable system without excess capacity.

a) How do YEC's proposed new planning criteria respond to these comments, in particular, that comment that the reliability criteria should result in a reliable system without excess capacity?

ANSWER:

YEC has not proposed the criteria set out in the Resource Plan, it has already adopted these criteria for the system, and they form the basis for YEC's planning activities.

a)

See YUB-YEC-2-1, YUB-YEC-2-2, and YUB-YEC-2-7.

YEC has adopted the new WAF planning criteria at 2 hours/year LOLE consistent with the low end of the probabilistic criteria used in other jurisdictions. It has also adopted an N-1 criteria consistent with typical planning throughout North America. As a result, the criteria are not too stringent by utility standards but are intended to result in a suitably reliable system without excess capacity.

The N-1 criteria in particular provides the only line of protection for WAF loads being able to be served during Aishihik line outages, which (regardless of measured probabilities) do occur and need to be planned for and accommodated. These events happening at the cold times of winter would lead to serious safety concerns without the N-1 criteria.

REFERENCE: **Review of the Capital Resource Plans of Yukon Energy Corporation and Yukon Electrical Company Limited. Report to Commissioner in Executive Council by Yukon by Yukon Utilities Board, December 7, 1992 (Page 92, Recommendation #16)**

QUESTION:

Please indicate the status of the decision support systems as described in Recommendation #16.

ANSWER:

A comprehensive review of available water management decision support systems (DSS) was done in 1997 resulting with the purchase of a Synexus Global Vista DSS system in 1998. The system was put into service in 1999 for the WAF grid. The Mayo grid was added in 2003 following the completion of the Mayo-Dawson transmission Project and the resulting increased use of the Mayo Hydro Facility. Prior to the completion of this transmission line the Mayo Hydro facility had been spilling more than 75% of its average available energy since the shutdown of the UKHM mine in 1989, hence there was no need for a more comprehensive DSS system for the Mayo Facility. More information about the Vista DSS system is available at their website: http://www.synexusglobal.com/index.html. This system is presently used by the water management group for inflow forecasting and for short and long term water management planning.

From 1992 up to 2006 Yukon Energy has continued to use Acres (now Hatch-Energy) MULRES model for its hydro resource planning for the purposes of assessing various supply option scenarios. Yukon Energy has an upgrade project planned for the VISTA system in 2007 to allow it to be used for the company’s future resource planning and also for operational dispatching as the two electrical grid loads grow to the point where this degree of water optimization has an increased benefit.

REFERENCE: **Review of the Capital Resource Plans of Yukon Energy Corporation and Yukon Electrical Company Limited. Report to Commissioner in Executive Council by Yukon by Yukon Utilities Board, December 7, 1992 (Page 97, Recommendation #20)**

QUESTION:

Have any further environmental costs been identified for the top storage at Marsh Lake?

ANSWER:

Yukon Energy would like to clarify that it is not considering the Marsh Lake top storage project described in the 1992 Resource Plan. That project involved using material storage above the existing water license and above natural high levels on the lake (up to 1 meter). The company is considering the Marsh Lake Fall/Winter Storage project, which is at most a modest revision to the water licence “full supply level” of 0.15 to 0.3 meters that is well within the natural high and in fact has been exceeded naturally 8 years out of the past 21 (40% of the time), with all gates open at the Lewes Control structure at the outlet of Marsh Lake.

Yukon Energy has not yet identified potential environmental costs of the Marsh Lake Fall/Winter Storage Project. The company met with local residents on September 11 accompanied by environmental scientists the company has hired to identify and quantify environmental impacts. The scientists spent several days in the field and are presently preparing preliminary field reports of their findings. The company will provide an update to the YUB and interested parties when it is available.

REFERENCE: **Review of the Capital Resource Plans of Yukon Energy Corporation and Yukon Electrical Company Limited. Report to Commissioner in Executive Council by Yukon by Yukon Utilities Board, December 7, 1992 (Page 103, Recommendation #22)**

QUESTION:

Please report on the costs and success of the DSM programs as identified in the 1992 Capital Resource Plan. Please list the results of each DSM program undertaken. Does YEC propose any future DSM programs?

ANSWER:

YEC's experience with DSM coming out of the 1992 Resource Plan hearing was limited and of minimal continuing effect. This is because as of the 1993/94 GRA, the Faro mine had closed and basically all integrated system DSM was curtailed due to 1) the resulting hydro surplus, and 2) the desire to minimize the rate impact arising from the closure of the Faro mine. This is set out in detail in the Board's Decision 1993-8 which basically restricted DSM spending in 1994 to solely public information.

YEC does not have any data on continuing benefits from the pre-1992 DSM programs, if any; however, given the nearly 15 year interval, little residual benefit is expected.

With respect to future DSM, YEC does not today propose to undertake any new programs. In the event loads on WAF develop to a point where diesel generation is on the margin in a sufficient magnitude to allow for cost-effective DSM to be pursued (consistent with the principles established in the 1992 YUB Resource Plan Report), YEC would likely be in a position to pursue DSM programs aggressively. Also see UCG-YEC-2-31(c).

REFERENCE: **Review of the Capital Resource Plans of Yukon Energy Corporation and Yukon Electrical Company Limited. Report to Commissioner in Executive Council by Yukon by Yukon Utilities Board, December 7, 1992. (Page 139, Recommendation #39)**

QUESTION:

Please report on the long-term hydrological data bases requested in Recommendation #39 and how that information has been incorporated into YEC's 20-Year Resource Plan.

ANSWER:

In 1995, Water Survey of Canada installed and operated on behalf of Yukon Energy stream gauging stations (with no real-time data collection platform) on Drury Creek and the Morley River. The stations were installed in order to provide hydrological data to support potential hydro sites on each river. The stations are still currently being operated. No long term gauging stations were installed on the Lapie or Orchay Rivers.

Available hydrological information would be one of the factors used to rank potential hydro sites in the 20-Year Resource Plan.

REFERENCE: YEC 20-Year Resource Plan, 4.3.3 Carmacks-Stewart Transmission Project (Page 29)

QUESTION:

"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."

a) What does YEC mean by "no net cost to Yukon energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy"?
b) Which option is being compared to provide the required capacity and energy?
c) Have any firm mine contracts been signed to support this option?
d) Explain how contributions from mine customers would be calculated for this option.
e) Provide an estimate of the expected contributions from customers to support this option.
f) Quantify the beneficial near term rate impacts for Yukon ratepayers from new mine firm energy.
g) Has the Yukon government confirmed funding for this project? Has the amount been determined?
h) If government funding, or the level of government funding, is unclear and if new mine firm energy is also uncertain, how does YEC propose the Board evaluate this proposal?
i) Have you completed a cost benefit analysis of this project? If so, provide all quantitative results.
j) What is the current status of this project?

ANSWER:

The reference provided is in the Overview submission. A more detailed update on this project was provided in the Supplemental Materials Tab 2 which was subsequently summarized in part in response to YUB-YEC-1-14.

a)

In saying that YEC seeks “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”, YEC means to ensure that development of this project does not increase net costs to YEC or ratepayers beyond what would otherwise be required without the project.

As reviewed in Supplemental Materials Tab 2 (page S2-1), by way of example, firm winter capacity needs might otherwise (without this project) be met with new diesel generation capacity while energy needs might otherwise be met by running more diesel fuel generation; the commitment here is that any costs charged to ratepayers for constructing the Carmacks-Stewart Transmission Project would not be any higher than what would otherwise be needed to meet capacity and energy requirements from diesel generation or other available resources.

The commitment also recognizes that the project will potentially enable YEC to access new major industrial mine customers to enhance revenues derived from current surplus WAF hydroelectric generation, thereby providing revenues to assist in funding the project and to provide potential benefits to Yukon ratepayers that would not otherwise be secured.

b)

In assessing options to the Carmacks-Stewart Project, YEC compares this project over the planning period with the next best available options to supply required WAF capacity and energy. In practice, based on requirements and options set out in the Resource Plan, this currently results in comparison with new diesel generation[1] and/or additional diesel fuel energy generation.

c)

No firm mine contracts have been signed to date to support this option. As reviewed in Supplemental Materials Tab 2 (page S2-5 and S2-7) with regard to the Minto mine, a Letter of Intent (LOI) has been signed with Minto Explorations Ltd. for negotiating a Power Purchase Agreement whereby the mine will purchase power from YEC's WAF

[1] As set out in the Resource Plan, the Carmacks-Stewart project will provide up to 6.0 MW of added firm capacity to the WAF grid (in addition to the Mirrlees Life Extension, Aishihik 3rd Turbine, and Marsh Lake Fall/Winter Storage) that would otherwise have to be secured from some other source. Alternative sources are practically limited to the Aishihik 2nd transmission line, or new diesel generation via the Whitehorse Diesel Replacement/Expansion Project, which is the default option.

grid as soon as the Carmacks-Stewart Project can facilitate this service prior to end of 2008. YEC does not intend to start construction of any stage of the project without having signed a firm contract with the Minto mine.

Western Copper has confirmed to YEC its interest in purchasing WAF gird power from YEC starting at the outset of its Carmacks Copper mine operations (located west of the Yukon River about 11 km west of the Carmacks Stewart Transmission Project), which Western Copper has estimated could begin as early as the third quarter of 2008. YEC is discussing with Western Copper the terms of a potential LOI to supply power to the Carmacks Copper mine through a new transmission connection near McGregor Creek to the Carmacks-Stewart Transmission Project. (See Supplemental Materials Tab 2, page S2-5 and S2-7)

d)

The LOI with Minto Explorations provides for the mine to contribute funding to the 138 kV Carmacks-Stewart Transmission Project, if it proceeds, equal to the estimated in-service costs for a 35 kV transmission line from Carmacks to Minto Landing; this funding commitment will in effect represent a pre-payment on the mine's power bills, and would be provided on condition that the mine would receive a "rebate" (in effect, an offset against its actual power bills) equal to the lesser of (i) 20% of the amount the mine pays for power charges in any year, and (ii) the remaining balance of this contribution. In addition, the mine will fully fund (without any rebates) all in-service costs for the 35 kV spur line (and related transformers, switches and fuses) from the Minto Landing area to the mine site. (See Supplemental Materials Tab 2, page S2-12)

YEC is seeking similar funding and rebate arrangements with the Carmacks Copper mine, assuming that the Carmacks-Stewart Project segment to serve this mine would be from Carmacks to the McGregor Creek area and that the mine load would require a 138 kV transmission connection (rather than the 35 kV connection needed to serve only the Minto mine load). (See Supplemental Materials Tab 2, page S2-12)

e)

As reviewed in Supplemental Materials Tab 2 (page S2-12), the initial estimate of the Minto mine pre-payment contribution for the Carmacks to Minto Landing segment of the project is approximately $4.7 million (2005$). The mine will separately fully fund all costs for the 35 kV spur line from Minto Landing to the mine site, the costs of which were initially estimated at approximately $2.4 million (2005$).

On the same basis, the initial estimate of the Carmacks Copper mine pre-payment contribution for the Carmacks to McGregor Creek segment of the project is approximately $6.0 million (2005$), reflecting the 138 kV requirement. (See Supplemental Materials Tab 2, page S2-13) The mine would be required separately to fund all costs for the 138 kV spur line from the McGregor Creek area to the mine site, the costs of which have been initially estimated at approximately $2.4 million (2005$).

f)

Beneficial near term rate impacts (measured initially in present value benefits over the life of the Minto mine and/or the Carmacks Copper mine) for Yukon ratepayers from sales of new mine firm energy under a range of different scenarios with the Carmacks-Stewart Transmission Project have been reviewed in Supplemental Materials Tab 2, and summarized in response to YUB-YEC-1-14. Net benefits are contingent upon several factors, including final project design specifications and costs, final agreements with the mines, and the magnitude (if any) of any YTG Infrastructure Funding provided to the project.

Looking solely at the potentially expected firm net rate revenues from the Minto and Carmacks Copper mines and ignoring costs and funding related to the Carmacks-Stewart Project, present value net operating income earned by YEC from supplying these two mines (net of rebates as well as any incremental diesel operating costs) over their expected lives has been estimated at $18.4 million. (See response to YUB-YEC-1-14 and Supplemental Materials Tab 2, pages S2-11 to S2-13) These estimates are subject to ongoing review and adjustment.[2]

g)

The Yukon government has not confirmed any funding for construction of the Carmacks-Stewart Transmission Project. As reviewed in Supplemental Materials Tab 2 (page S2-14), Yukon Energy proposed to the Yukon Government last spring that YTG Infrastructure Funding be committed to provide $10 million of the project cost (2005$), with $5 million for Stage 1 costs (Carmacks to Pelly Crossing) based on the assumption

[2] By way of example, the referenced estimate for the Minto mine net operating revenues (prior to rebates) assumed a net ratepayer operating benefit of 10 cents per kWh, and annual sales of 24.5 GWh/year for six years (present value of $11.6 million at 7.5%/year nominal discount rate). The actual rate to be charged will be determined only after cost of service determination for the Large Industrial customer rate class as required under OIC 1995/90 (the applicable Rate Schedule 39, which currently is interim, plus the current Rider F as would apply to this customer would currently yield an average rate of approximately 9.6 cents/kWh; however this rate was last determined for the Faro mine in 1996/97 and thus does not reflect any of the cost of service factors impacting the current Rider J – however, full Rider J effects, which if applied might currently yield an average rate of 10.9 cents/kWh, may not in fact apply to this class of customers when the new rate is determined by the YUB).

that at least one mine (i.e., the Minto mine) proceeds on its current schedule. A condition of the proposal was that, prior to construction, YEC proceeds with all permitting and approvals, including any access rights required to cross First Nation settlement lands, as needed to proceed with the full Carmacks-Stewart Project (Carmacks to Stewart Crossing).

h)

Given that government funding and new mine firm energy are both uncertain at this time, Yukon Energy proposes that the Board assess (in the context of the Minister's June 5, 2006 terms of reference) the necessity of the proposed spending commitments and their consequences in meeting electric load forecast requirements (including requirements related to these potential new major industrial customers) and in affecting electricity rates to be charged to Yukon consumers, and evidence that all reasonable alternative options have been considered, in order to determine the conditions under which the Carmacks-Stewart Transmission Project proposed spending could prudently proceed, in whole or in part, on reasonable grounds and in the interests of Yukon ratepayers after analysis of the potential risks from all causes.

YEC has reviewed the key factors affecting the project economics, cost-benefits and financial options (see response to YUB-YEC-1-14, based on Supplemental Materials Tab 2). The benefits of the full project are estimated to exceed its estimated costs, even without YTG funding, if both mines are developed and supplied starting in late 2008 and for the mine lives assumed. The extent to which this picture changes dramatically is also reviewed if only the Minto mine is assumed to be operating with the assumed purchase power arrangements. As noted, Yukon Energy would not proceed with construction of any part of this project without a firm purchase power agreement as required with at least one of the two mines.

Various combinations of YTG funding and Yukon Energy funding options for proceeding with Stage 1 (only to Pelly Crossing) and/or the full project (Carmacks to Stewart Crossing) are reviewed in the Supplemental materials Tab 2 (pages S2-14 and S2-15) and summarized in the response to YUB-YEC-1-14.

One potential option is to structure Yukon Government funding to address the identified risks while providing the security needed to ensure long-term infrastructure funding investments can be made without undue near term risks to current ratepayers. Under this option, Stage 1 development (Carmacks to Pelly Crossing) could be committed clearly to the 138 kV transmission design approach concurrent with only the Minto mine development, and Stage 2 development (Pelly Crossing to Stewart Crossing) of the grid connection project could be timed as soon as feasible thereafter (potentially concurrent with Carmacks Copper mine development). In assessing this general option, assessment is required, pursuant to the Minister's June 5th letter, of both the appropriate amounts of Yukon Government funding as well the related terms and conditions.

For the option that assumes no Yukon Government funding, Yukon Energy would need to focus on what can be prudently funded solely by ratepayers. The challenge in this situation becomes particularly acute if only the Minto mine is committed to development. Without at least the Minto mine, and without any Yukon Government funding, Yukon Energy would not propose in the near term pursuing any form of this project.

In summary, without both mines and/or Yukon Government funding as required to prevent adverse ratepayer impacts, Yukon Energy would not expect to proceed at this time with the full Carmacks-Stewart Project to connect the two grids. Under these conditions, YEC has identified and reviewed in the referenced filings two options to be considered at this time:

- **Short-term Mine-Focused Option** – Yukon Energy would focus under this option on short-term economics, developing the least cost transmission to serve the two mines when they each develop, as well as 35 kV transmission to Pelly Crossing as soon as this becomes feasible. This option in particular is being considered in the event that only the Minto mine development proceeds or is firmly committed over the next several months prior to final design and start of construction, in which case the LOI with Minto Explorations provides for the entire transmission connection to be developed at only 35 kV. The short-term option would forego using the current development opportunities to develop long-term infrastructure capable of connecting in future the WAF and MD grids, i.e., some or all of what is developed between Carmacks and Pelly Crossing would be at 35 kV, and thus incapable of being used in future for a connection of these two grids.

- **Long-term Infrastructure Option -** Yukon Energy would incur under this option the added costs needed to establish the 138 kV infrastructure as needed for Stage 1 (from Carmacks to Pelly Crossing) of the ultimate grid connection. The following analysis was provided of this option in the Supplemental Materials Tab 2 based on the initial assumptions and estimates provided therein, underlining the extent to which this option's economics are affected by the near-term development of one versus both mines in this area:
    - If only the Minto mine was developed, this added cost (relative to the Mine-Focused Option) would approximate at least $7.6 million,

resulting in total YEC costs of about $13.3 million compared with ratepayer benefits of about $11.3 million.

- o In contrast, if both mines were to be developed, this added cost would approximate at least $5 million, resulting in overall YEC costs ranging between $7.3 million and $10.6 million compared with ratepayer benefits of about $20.7 million.

i)

Yukon Energy has provided its initial cost-benefit assessments, including quantitative results, for various options for developing this project (see summary response to YUB-YEC-1-14, based on Supplemental Materials Tab 2). These assessments continue to be updated.

j)

The current status of the Carmacks-Stewart Transmission Project is in the midst of pre-decision planning as follows (see diagram at page 4 of Overview of Yukon Energy's Resource Plan Submission):

- **Arrangements for potential Yukon Government Infrastructure Funding**: this was an initial step, and resulted in initial Yukon Government funding for initial planning activities ($450,000); discussions are ongoing with Yukon Government as to potential infrastructure funding support for this project
- **Consultation with First Nations and others**: this has been ongoing since fall 2005; an MOU was singed with the Northern Tutchone First Nations (NTFN) in May 2006, and consultations are proceeding pursuant to that MOU (the parties are currently completing consultations as needed to finalize a preferred route for the project so that YEC can file its Project Proposal with YESAB; thereafter, a Project Agreement will be negotiated over approximately the next six months)
- **YUB review for project costing over $3 million**: this is being addressed in the current YUB hearing, pursuant to the Ministers' June 5, 2006 terms of reference, with the Board to report to the Commissioner in Executive Council by January 15, 2007.
- **Environmental assessment and licensing**: YEC has been working since fall 2005 to prepare the necessary filing, and expects to file shortly its Project Proposal with YESAB; copies of this filing will be made available thereafter to the YUB and participants in the current YUB hearing. This filing sets out a preferred route selected for the project along with basic specifications as

needed for assessment of expected environmental and socio-economic effects as required for licensing and permitting, including an anticipated schedule for carrying out the project. The YESAB process and related review and approval by decision bodies is expected to continue until next spring/early summer. Final decisions on proceeding with the project cannot be taken by YEC until this process is completed.

- **Arrangements with major mine customers**: YEC has initiated discussions with developers of both the Minto mine and the Carmacks Copper mine to secure purchase power arrangements in support of the project; a Letter of Intent was signed with Minto Explorations in March 2006, pursuant to which a Purchase Power Agreement is currently being negotiated (target to complete as soon as feasible this fall) based on the expectation that this mine will commence commercial operation by mid 2007 and will secure grid power from YEC (through the project) by fall 2008 (to meet this target, YEC estimates that it would need to commence construction of at least Stage 1 during summer 2007). YEC is currently seeking to confirm, as soon as feasible this fall, the interests and intent of Western Copper in a similar LOI to secure WAF grid power in the near term.
- **Final design, costing and contracting:** YEC has initiated discussions with potential engineering consulting firms qualified to develop final design, costing and tender documents for the project; YEC expects to complete shortly a tendering process for these engineering services in order that the necessary work can be carried out concurrently with other activities between now and next spring/early summer.
- **Tendering process to obtain final costs:** YEC currently estimates that, subject to the progress achieved with the YESAB review process, tendering of long lead equipment (with cancellation provisions) will proceed during the second quarter of 2007 and that tendering of construction contracts (in order to confirm final contract costs) would occur shortly before securing all final approvals and permits.
- **YEC Decision to proceed with construction –** in accordance with the Resource Plan, this decision by YEC's Board of Directors will only be made after all of the above planning activities for the project are satisfactorily completed (including, in addition to the YUB report to the Yukon Government and all permits and regulatory approvals, resolution as required of contracts with one or more mines, a Final Project Agreement with NTFN, final resolution as to any Yukon Government funding, and acceptable contract tender document submissions to carry out the needed construction). Also, Yukon Energy requires the YDC Minister's approvals under OIC 1996/108 before its Board can decide to proceed with the project. In order to meet

overall targets for in-service during the third quarter of 2008, YEC requires the final Board of Directors' decision to occur around mid 2007.

REFERENCE: **YEC 20-Year Resource Plan, 4.3.4 Mirrlees Life Extension Project (Page 30)**

QUESTION:

"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."

a) If the Board does not approve YEC's new capacity criterion as proposed, and if the Aishihik, Marsh Lake, and Carmacks-Stewart options proceed, is the Mirrlees Life Extension Project necessary?
b) List the weaknesses associated with the Aishihik transmission line.
c) Operationally, how has YEC overcome these weaknesses in the past?
d) Should an alternative for the Aishihik transmission line be considered to overcome any perceived weaknesses? Should this option be given a higher priority that the Carmacks-Stewart transmission line? Why or why not? Would this option (Aishihik transmission line) have lower environmental costs?

ANSWER:

a)

Yukon Energy is not seeking "approval" of the new capacity planning criteria that it has adopted. The capacity criteria has been adopted by Yukon Energy's Board of Directors based on, among other things, the recommendation of Dr. Billinton.

Pursuant to the Minister's June 5, 2006 terms of reference for the current review, the Board is to consider specific matters when reviewing the necessity, characteristics and consequences of specific proposed near term spending commitments on new generation and transmission projects. One specific consideration noted by the Minister for the Board's review is:

> "ii) the capability of existing generation and transmission facilities to provide reliable electrical power generation to meet the load forecast requirements in (i), taking into consideration capacity planning criteria appropriate and adequate to establish requirements for such electrical power generation capacity in accordance with principles established in Canada by regulatory authorities of the government of Canada or of a

province or of a Territory regulating hydro and non-hydro electric utilities;”

Table 1 below attempts to apply for the year 2012 the previous capacity planning criteria used from 1992 through 2005 to the combined WAF/MD system assuming as requested that the Aishihik 3rd Turbine, Marsh Lake fall/Winter Storage and Carmacks-Stewart Transmission Project are all in place.[1]

Based on the assumptions adopted in Table 1, the system will meet the former planning criteria in 2012 without the Mirrlees Life Extension Project if Aishihik, Marsh Lake, and Carmacks-Stewart options are all in place and Base Case loads occur. This is because the combined WAF/MD firm peak loads in 2012 (excluding secondary sales) under the Base Case is 70.4 MW, with the Maximum Allowable Peak Load (MAPL) under the previous criteria is 78.4 MW as set out in Table 1. Since Carmacks-Stewart is likely to proceed only with one or both of the Minto or Carmacks Copper mines, this criteria would continue to be met to the extent the coincident peak loads of the mines do not exceed 8.0 MW.

[1] The past (1992) planning criteria did not consider a WAF system that extended up to Mayo and Dawson. As such, it may be an unrealistic extension of the planning criteria to solely retain the degree of reserve (15 MW plus 10% diesel) that was used in 1992-2005.

Table 1: Application of Previous Capacity Planning criteria to system with Aishihik 3rd turbine, Marsh Lake Fall/Winter Storage and Carmacks-Stewart Transmission in place

Unit	Rating (MW) Today	Rating (MW) 2012 assuming Aishihik 3rd Turbine, Marsh Lake Fall/Winter Storage and Carmacks-Stewart
Whitehorse Hydro (winter - for all units)	24.0	25.6
Whitehorse diesel #1	3.0	
Whitehorse diesel #2	4.2	
Whitehorse diesel #3	4.2	
Whitehorse diesel #4	2.5	2.5
Whitehorse diesel #5	2.5	2.5
Whitehorse diesel #6	2.7	2.7
Whitehorse diesel #7	3.3	3.3
Faro diesel #3	1.0	1.0
Faro diesel #5	1.3	1.3
Faro diesel #7	3.0	3.0
Aishihik #1	15.0	15.0
Aishihik #2	15.0	15.0
Aishihik 3rd Turbine		7.0
Carmacks diesel (YECL)	1.3	1.3
Haines Junction diesel (YECL)	1.3	1.3
Teslin diesel (YECL)	1.3	1.3
Ross River diesel (YECL)	1.0	1.0
Dawson Diesel		4.3
Mayo Diesel		2.0
Stewart-Crossing Diesel		0.3
Mayo Hydro		5.4
Fish Lake hydro (2 units - YECL)	0.4	0.4
Total	87.0	96.2
Less: 15 MW hydro Reserve	-15.0	-15.0
Less: 10% Diesel Reserve	-3.3	-2.8
Maximum Allowable Peak Load (MAPL)	68.7	78.4

b)

The Aishihik transmission line (including all connections from the Aishihik generation site to the Whitehorse substation facilities) is a non-redundant transmission line that connects material WAF generation to the major load centres. As such, potential for loss of the Aishihik line exposes the major WAF load centres to outages, particular at times of peak winter loads. This weakness was fully demonstrated by the power outage in January 2006 caused by a loss of the Aishihik connection to the major load centres.

c)

Operationally, in the past YEC has overcome the weaknesses associated with Aishihik transmission line by planning the system such that major loads at Faro (the Faro mine) were effectively "curtailable" on the upper portions of their load (the Faro mine would peak at about 25 MW; however, local diesel generation was only about 13 MW, so during transmission line outages the mine would be reduced operationally to about half-load). The resulting system had sufficient generation on-site in Whitehorse and all other communities to effectively meet the winter peak loads.

This well-protected condition only eroded when the Faro mine closed and the corresponding capacity retirements were slated to occur to a modest degree at Faro and to a large degree at Whitehorse. As a result, there was the potential for a scenario to arise with respect to grid generation that had not occurred for many years (if ever) in Yukon; that is having a major community (in this case Whitehorse) without sufficient local generation to meet its own winter peak. This was the condition that led YEC to retain Drs. Billinton and Karki to assess the system, and ultimately to recommend the planning criteria YEC has since adopted.

d)

The Aishihik 2nd transmission line project is discussed in detail in the Resource Plan at section 4.3.8 and in YUB-YEC-2-11. Yukon Energy seriously considered this project, and provided detailed assessment in the Resource Plan. This project only supplies firm capacity (no new energy) to the WAF system, but along with firm capacity benefits (increased load carrying capability under N-1 of at least 15 MW, 22 MW if Aishihik 3rd turbine is developed; and increased load carrying capability under LOLE of 8 MW, about 15 MW if Aishihik 3rd turbine is developed), the line would also provide:

- greater system security (from being an "express" configuration compared to the existing line, which has a number of PT connections along its length)
- operational benefits in terms of being able to take one line out of service and maintain the Aishihik GS on-line (and potentially at times avoided diesel generation for this condition
- Potential for further future capacity benefits to the extent the Aishihik units 1 and 2 are upgraded either through re-rating after the current re-wind process, or

through future re-runnering for increased capacity output – this benefit cannot be captured with solely one line, due to the N-1 and LOLE constraints.

However, as reviewed in response to YUB-YEC-2-11 (c), given the current options for capacity on the system, and in particular the Mirrlees Life Extension project, the Aishihik 2nd transmission line was not the lowest cost capacity alternative, had certain other disadvantages relative to the Mirrlees option (e.g., time requirements, flexibility and risk) and also did not offer other opportunities associated with the Carmacks-Stewart Transmission Project (e.g., new mine loads, system benefits, economic development benefits in the region). The Aishihik 2nd Transmission line also raises additional issues that should be noted:

- When compared to the near term diesel generation options noted in the Resource Plan, the new transmission line option costs and timing for development are both more risky and uncertain to assess. Licensing and planning requirements both require more time and costs for the new transmission options than for the identified diesel generation options. Prior to receipt of actual tender quotes (after design and most other planning costs have been incurred), transmission construction costs are also more difficult to assess than the identified diesel capacity installation options.
- The Carmacks-Stewart Transmission Project has been under active planning by YEC for over a year to secure substantial benefit opportunities to ratepayers from the near term opportunity to sell material amounts of surplus hydro and as well the opportunity to secure YTG Infrastructure Funding for development of a long term connection of the WAF and MD grids.

As reviewed in response to YUB-YEC-2-11 (c), the Aishihik 2nd Transmission Line is not an alternative to the Carmacks-Stewart project, as the Carmacks-Stewart project provides a range of benefits not provided by the Aishihik 2nd Transmission Line (including being able to sell near term surplus hydro generation to mining customers, and being able to provide ongoing flexibility, efficiencies and other benefits from connecting the WAF and MD grids).

Neither Carmacks-Stewart nor the Aishihik 2nd transmission line are expected to have material “environmental costs” given the nature of transmission developments and, in addition, given their location in each case in close proximity to existing linear developments (highways and/or existing transmission). Stage One of the Carmacks-Stewart Project, however, is expected to result in the displacement of material diesel generation with its associated emissions (GHGs)[2], while Stage Two would enable further such benefits through more efficient use of surplus hydro generation on both the WAF and MD systems. Similar environmental benefits from incremental diesel generation displacement are not expected with the Aishihik 2nd Transmission Project.

[2] At a minimum, Stage One would displace the diesel generation at Pelly Crossing (about 2 GW.h/year); if the Minto Mine is operating, Stage One would displace about 32.5 GW.h/year, which exceeds all utility diesel generation in Yukon per year since completion of the MD project.

REFERENCE: **YEC 20-Year Resource Plan, 4.3.8 Schedule and Sequencing (Page 32)**

QUESTION:

"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)."

On page 3 of YEC's 20-Year Resource Plan, YEC states "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."

a) Given that there is surplus energy and that the Aishihik Third Turbine Project does not contribute to WAF firm capacity shortfalls, why is this option being considered?

ANSWER:

a)

The Aishihik 3rd turbine project is being considered due to the benefits it provides the system in terms of displaced diesel generation, either via reduced peaking diesel generation or, eventually, via reduced baseload diesel generation.

The Aishihik 3rd turbine project provides three potential benefits to the WAF system, depending on the conditions of the system at any given time.

- **Following the period when the WAF system reaches full utilization of the existing hydro (i.e. over the long-term or in the case of development of major new industrial loads in excess of 10 MW)**, the Aishihik 3rd turbine will allow more efficient use of the water at Aishihik, that is expected to result in 5.4 GW.h per year of increased average annual output.
- **In conditions where the LOLE criteria dominates the need for new WAF capacity (i.e., in the event of material industrial development in excess of about 7 MW),** such as if major new industrial loads connect to WAF, the unit

contributes 0.6 MW to the load carrying capability (it contributes 0 MW when N-1 is the dominant criteria as it is dependent on the Aishihik Transmission Line).

- **Prior to this time, while N-1 is the dominant criteria and there remains WAF surplus hydro (i.e., in the short-term assuming no major new mines in excess of about 5-10 MW),** the Aishihik 3rd turbine contributes an ability to meet key short-term peaking requirements (for loads above about 54 MW, i.e., during very cold winter periods) using hydro resources rather than having to start diesel generators. As such, the unit contributes to the ability to save costs of diesel fuel. In the very early years (2006, 2007, 2008) under base case loads this contribution is relatively small (less than 100 hours a year), however the requirement for peaking diesel grows quickly with load growth and is sufficient at today's diesel prices to make the project economic in the next few years.
- **Under any future potential scenario where the Aishihik 2nd Transmission Line is constructed:** The third turbine will provide about 7 MW of reliable capacity to both the N-1 and LOLE criteria.

REFERENCE: **YEC 20-Year Resource Plan, 5.0 Industrial Development Opportunities (Page 34)**

QUESTION:

"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."

a) Given this statement, why would YEC consider any of the opportunity projects?
b) For new industrial loads, how long does YEC have from when it first hears of a project until that project proceeds?
c) What criteria does YEC use before committing any resources to plan for new loads? What critical points need to be satisfied to move from the study phase to the planning phase to the construction phase? Generally, what kind of time frame is required?

ANSWER:

a)

The three opportunity projects are each being pursued to secure potential economic net benefit for Yukon ratepayers. Yukon Energy has an obligation to ensure that it maximizes the benefits and capabilities of existing assets that ratepayers are paying for. This focus is a primary consideration and driving factor throughout the Resource Plan.

The potential benefits from the "opportunity projects" derive from various factors not related to the current surplus of average annual hydro generation:

- The Carmacks-Stewart project is being pursued (as set out in section 4.3.4 and YUB-YEC-2-21) "as a key Yukon territorial infrastructure initiative to meet a specific window of opportunity related to two potential new mines (Minto and Western Silver at Carmacks Copper) and current Yukon Government Infrastructure Funding". It also provides, if developed, up to 6.0 MW of capacity benefits, which are required on the WAF system in the near-term.
- The Aishihik 3rd Turbine is being developed, as set out in section 4.3.2 and Appendix C, as an economically beneficial means of avoiding peaking diesel use on the WAF system, and ultimately as a means to provide enhanced long-term

average hydro capability from Aishihik once the system returns (as forecast) to a point of diesel on the margin.

- The Marsh Lake Fall/Winter Storage project is being pursued, as set out in section 4.3.3, as a means to ensure the capability of the existing assets are maximized and to provide 1.6 MW of relatively low-cost firm capacity to the WAF system (and also provide peaking benefits, similar to the Aishihik 3rd turbine). Over the long-term, this project will also provide enhanced long-term average hydro capability from Whitehorse Rapids once the system returns to a point of diesel on the margin.

b) and c)

Virtually every mining project that is in exploration, feasibility or permitting stages of development is located on properties with well known deposits that have been identified and mapped by companies and the Yukon Government, in many cases for up to 100 years. In other words, the deposits are not new.

What does change, of course, is the ownership of mineral rights, the world price of the mineral and other external factors. An excellent source of known mineral deposits in the Yukon is an annual publication from the Yukon Governments Department of Energy, Mines and Resources entitled “Yukon Mineral Property Update”. Another source is an annual publication from the Yukon Geological Survey entitled “Yukon Mineral Deposits”.

The difficulty is not in hearing about a deposit but rather in understanding when the factors have changes to the extent that a particular deposit may be economic to develop and that the owner of the mineral rights has the capital to move it forward to the next stage (or further) of development. Since 1987, when YEC acquired the NCPC assets, there have been two major mine customer closures (UKHM and Faro) and no new industrial mine customer connections.

Yukon Energy proactively engages prospective industrial mining customers by maintaining active participation in the local Chambers of Mines and Chambers of Commerce, attending local and regional mining shows and conferences and with one-on-one meetings with mining company officials.

Overall, the time frame from when YEC hears about a project to when the project proceeds can be expected to vary significantly depending on the individual circumstances of that particular mineral property, the stage of development and the ownership of the property. Typically YEC monitors with increasing intensity the property development from exploration, to prefeasibility, to environmental permitting, to raising of capital funds needed for construction, to start of construction and lastly the in-service date.

Depending on the length of line and voltage required for a grid connection, it may well take YEC the same length of time to get through the environmental permitting and construction phases as the mine. If new electrical supply (other than diesel, e.g. new hydro) is required to serve the industrial customer, then a materially longer period may be required for YEC than it takes to develop a mine project.

As an example, potential mines in the Minto and Carmacks Copper area have been well-known for many years. The Minto mine has even been licensed for many years – and had some infrastructure developed in the past. However it was not until early 2006 that the Minto project proceeded to a stage where YEC was able to enter into negotiating a Letter of Intent with the mine (signaling an initial commitment to develop grid interconnections and to buy power from the utility). Carmacks Copper, another project that has been well known for a long time, has not to date proceeded to completion of its licensing or to negotiation of a Letter of Intent with YEC to purchase power. With current planning (assisted at the outset by YTG funds), and assuming concurrent YUB reviews as part of this proceeding and YESAB reviews, the transmission project connection needed for the Minto Mine will proceed to construction for in-service to Minto in late 2008. However, this specific example has been more rapid than may be typical, as YEC did prior planning for the Carmacks-Stewart Transmission prior to 2005 and the Yukon Government provided the first substantial part of the project planning funding in later 2005/early 2006 as a no-cost contribution, allowing YEC to commit to more major planning activities at the outset than may be otherwise justified by a utility spending solely ratepayers money.

YEC focuses on staging its approach to management of potential industrial customer loads and new supply options based on sound risk management principles, such as:

Allocation of resources is matched to the revenue potential and stage of development of the mining project

- Approval of on-going costs related to resource planning, collection of hydrological data is reviewed on an annual basis
- Oversight of expenditures is provided by senior management, and when required signoff by YEC Board of Directors
- In assessing its commitment of time and resources towards industrial load opportunities, YEC is attentive to the mining company proceeding to make an

application for environmental permitting, obtaining the required permits and lastly raising of sufficient funds to complete construction.

REFERENCE: YUB-YEC-1-6-e

QUESTION:

"Retaining the previous criteria indicates that today the system would be sufficient with all 3 Mirrlees units retired. Based on the experience of Yukon during the January 29 outage, reliable utility standard electrical supply could not be provided by YEC if its system were with the three Mirrlees units today."

a) Over the past 10 years, what has been the frequency of outages like the one that occurred on January 29?
b) If the Marsh Lake and Carmacks-Stewart options proceed, could reliable utility standard electrical supply be provided by YEC? Would the Carmacks-Stewart transmission project suffer from the same weaknesses as the Aishihik transmission line?

ANSWER:

a)

See YUB-YEC-1-6(a). The frequency of outages on the Aishihik line is very low - 3 recorded outages in 8 years. However, the unavailability of this line related to those three outages is approximately equal to the CEA averages for this type of line.

b)

No, if only Marsh Lake and Carmacks-Stewart proceed, but not Mirrlees Life Extension or Aishihik 3rd turbine, YEC could not provide utility standard electrical supply to 2012. YEC defines utility standard electrical service as confirming to reasonable planning criteria as used by utilities elsewhere. In Yukon, this would entail meeting an LOLE of 1 to 2 hours per year and being able to survive the first failure (or N-1), which are two standards typically used by other utilities. Were these two projects pursued alone (without the other projects outlined in the Resource Plan, or equivalent) it would leave substantial capacity shortfalls (about 11.5 MW) compared to utility standard service (i.e., compared to the N-1 standard; using a LOLE standard of 2 hours/year the shortfalls would likely approximate 5.3 MW).