IN THE MATTER OF YUKON ENERGY CORPORATION 20-YEAR RESOURCE PLAN: 2006-2025

FINAL ARGUMENT

YUKON ENERGY CORPORATION

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1.0 INTRODUCTION

The current Yukon Utilities Board (the "YUB", or the "Board") review of Yukon Energy's 20-Year Resource Plan (the "Plan") is a very significant step for Yukon Energy Corporation (Yukon Energy or YEC) and stakeholders, both from the perspective of ensuring Yukon Energy's capital planning processes are scrutinized in an open and transparent manner and further to ensure that any proposed major capital projects are publicly reviewed by the YUB prior to Yukon Energy going ahead with construction (Morrison, transcript page 19, lines 12 to 19). In order to set the stage for a more detailed review of key issues, this introduction will provide a general overview of the following subject areas:

- Yukon Energy's Resource Plan.
- Scope for this Board review.
- Yukon Energy Final Argument.

1.1 OVERVIEW OF YUKON ENERGY'S RESOURCE PLAN

The Plan was submitted to the YUB on June 1, 2006 to facilitate YEC's commitment to seek prior YUB review of major capital projects costing $3 million or more, and to provide a clear planning context within which the Board could review and recommend on such projects[1]. Yukon Energy's earlier commitments to seek YUB review of the matters set out in the Plan include:

- Commitment in Yukon Energy's April 11, 2006 letter to the YUB (Exhibit B-25), addressing the January 29, 2006 Whitehorse-Aishihik-Faro ("WAF") system outage, to file with the YUB by June 1, 2006 its 20-Year Resource Plan addressing major electrical generation and transmission needs in Yukon from 2006 to 2025;
- Commitment in Yukon Energy's December 2004 Application to the YUB regarding 2005 Required Revenues and Related Matters (as well as in YEC's response to YUB-YEC-1-33.3 in that hearing) to bring forward to the YUB new or revised capacity planning criteria in advance of capital investment in new generation for capacity reasons; and
- Commitment during and prior to the 2005 YUB hearing to find a mechanism for YUB review, prior to construction, of any new capital projects costing $3 million or more.[2]

In addition to outlining Yukon Energy's capital planning process, and how it deals with long term planning issues, the Plan as updated in Exhibit B-16 proposes for YUB review three generation and transmission

[1] See Exhibit B-9, page 2. In this regard, Yukon Energy's approach is consistent with principles set out in the BCUC Resource Planning Guidelines (December 2003) (Exhibit C3-12) which state, at page 2, that applications for BCUC approval of specific project Certificates of Public Convenience and Necessity in most circumstances should be supported by resource plans filed with the BCUC.

[2] This commitment was made several time during the 2005 hearing, e.g. Mr. Morrison response to Mr. McMahon, transcript in that hearing at page 703, lines 15 to 18: "...we have proposed and are proposing that we will find a mechanism, some mechanism, to ensure that we have this Board review all capital projects greater than $3 million." See also Auditor General's February 2005 Report on Mayo-Dawson Transmission Project (Exhibit C3-13), Management's Response at page 9, paragraph 35: "The Corporation is proposing to establish a process that would require projects greater than $3 million to receive prior approval by the Yukon Utilities Board." In the current proceeding, Mr. Morrison reviewed with Mr. Buonaguro the rational for the $3 million threshold, noting that it is lower than the $5 million threshold applicable in the Northwest Territories (transcript page 206, line 7 to page 207, line 9).

capital projects which require commitments by Yukon Energy before the year 2009 for investments of $3 million or more, namely:

- The Mirrlees Life Extension Project to address WAF capacity shortfalls;
- The Aishihik 3rd Turbine Project offering opportunities to displace WAF diesel generation; and
- The Carmacks-Stewart Transmission Project offering opportunities to sell near term surplus hydro power to new mines and to connect the two grids for long-term benefits of having this key infrastructure connecting the two hydro based grids in the Yukon.

With regard to the planning context for these proposed major projects, the Plan addresses electrical generation and transmission requirements in Yukon during the 2006 to 2025 period, reflecting Yukon Energy's role as the primary generator and transmitter of electrical power within the Territory, particularly with regard to the Yukon grids[3]. It provides background information on the planning process and the Yukon power systems, the new capacity planning criteria adopted by Yukon Energy, the near and longer term capacity and energy requirements on the two grids, and the resource options available to meet these requirements. Near term WAF capacity shortfalls are identified, establishing the need for new generating capacity to meet winter peak loads. The current surplus hydro energy generation on the two grids is outlined, and near term industrial developments are identified that may absorb this surplus and establish new opportunities for system enhancements to displace diesel generation.

The Plan also addresses planning activities that may be required by Yukon Energy to start construction on other major projects before 2016 to meet the needs of potential new major industrial customers or other potential developments in Yukon. Four broad scenarios are provided outlining different sets of opportunities that may rise during the 20-year planning period.

1.2 SCOPE FOR THIS BOARD REVIEW

There is no legislative framework currently in place in Yukon (outside of a revenue requirement or rate hearing process) to mandate the YUB to review or approve the Plan or major capital projects of Yukon Energy.[4] However, the Minister's letter of June 5, 2006 (Exhibit A-1) establishes a mandate pursuant to Section 18 of the *Yukon Utilities Act* (the "Act"). Pursuant to the Minister's direction, the Board is mandated to proceed with "a detailed and thorough review" of Yukon Energy's Plan "regarding proposals in respect of major electrical generation and transmission ["bulk electrical"] requirements in Yukon during the period 2006 to 2025" with emphasis on:

a) The above three major near term YEC projects related to the Plan involving expected capital commitments by Yukon Energy before 2009 of $3 million or more; and
b) Planning activities related to the Plan which YEC may be required to carry out in order to commence construction on other projects before 2016 to meet the needs of potential major industrial customers or other major potential developments in Yukon.

[3] Morrison, transcript page 18, lines 11 to 18. On overlaps with YECL in 1992 Resource Plan and YEC attention to non-grid areas, see also Osler, transcript page 154, line 18 to page 155, line 12 and Bowman, transcript page 156, line 18 to page 158, line 13.
[4] This matter was reviewed by Yukon Energy in Exhibits B-9 and B-10 (particularly Attachment A).

The scope of the Board's review and report by January 15, 2007 includes consideration of the need for and alternatives to the three proposed near term projects costing $3 million or more, and more specifically consideration of:

a) **significant utility spending commitments**: significant utility spending commitments related to bulk electrical requirements in Yukon that would affect long term utility costs and rates;
b) **effects on utility rates:** the effects of the proposed spending commitments on electricity rates to be charged to Yukon consumers;
c) **re: generation and transmission projects**: with regard to the proposed near term major generation and transmission projects, "...the necessity for the proposed spending commitments and, to the extent currently known, their physical and engineering characteristics and their economic consequences..." with emphasis on several specific considerations including:
    i. **Need for project spending commitments to meet load forecast requirements**: the effects relating to electrical load forecast requirements, including requirements related to potential new major industrial customers or other major potential developments in Yukon, and the need for the spending commitments to meet such load forecast requirements;
    ii. **Capability of existing generation and transmission facilities to meet load forecast requirements**: the capability of the existing bulk electrical facilities to provide reliable electrical power generation to meet the above load forecast requirements under (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";
    iii. **Consideration of options and selection on reasonable grounds**: evidence that all reasonable alternative options have been considered and that the proposed spending commitments on these projects have been selected on reasonable grounds, "i.e., technical feasibility, cost efficiency and reliability"; and
    iv. **Consideration of risks**: the analysis by YEC "...of potential risks from all causes, including but not limited to economic and financial risks, and including possible modifications to design or schedule resulting from environmental review and related regulatory approvals".

Yukon Energy has confirmed that the scope established by the Minister's June 5th letter provides the comprehensive and detailed YUB review sought by YEC of the Plan's major capital projects ($3 million or more).[5] Yukon Energy, as well as the Minister responsible for Yukon Development Corporation ("YDC")[6], will be able to review and consider the Board's recommendations before any final project decisions involving commitments of $3 million or more.

[5] See Morrison, transcript page 129, line 1 to page 130, line 7. Also Osler, transcript page 130, line 18 to page 131, line 12.
[6] YEC's submissions (Exhibit B-9 and B-10, Attachment A) have noted that the Carmacks-Stewart Project in particular cannot proceed without approval of the Minister responsible for YDC under OIC 1993/108.

Through Board Order 2006-8, the Board provided the final issues list for the public hearing and ruled that none of the projects identified in the Plan presently fall under Part 3 of the Act, and that environmental considerations are within the scope of the review (limited to general comparative information in terms of potential economic impacts to ratepayers).

1.3 OVERVIEW OF YUKON ENERGY FINAL ARGUMENT

In addition to the Plan, substantial additional information and documentation has been provided by Yukon Energy, including:

- Responses to two rounds of information requests from the Board;
- Responses to one round of information requests from two intervenors (UCG and YCS);
- A public workshop for all interested parties;
- A pre-hearing conference and related subsequent filings in response to the Board's request for comments on specific issues;
- Added filings by YEC to update participants on the major near term projects[7]; and
- Almost three full days of public hearings involving extensive cross examination of Yukon Energy and the filing of additional exhibits and undertakings.

Yukon Energy submits that a detailed and thorough review by the Board of the Plan and the three proposed major near term projects, as directed by the Minister, has been held and that YEC has provided all currently available information sought by the Board and intervenors on the matters within the scope of this YUB review.

Although no intervenor evidence was filed, UCG was assisted in its intervention by external legal counsel from the Public Interest Advocacy Centre in Ottawa.

In response to the scope directed by the Minister for the Board's review and report, Yukon Energy's Final Argument sets out support for the Board to recommend each of the three major projects proposed in the Plan with commitments of $3 million or more before 2009 (focusing on consideration of the specific issues set out in the Minister's June 5th letter regarding such projects), and for the Board to recommend the planning activities related to the Plan which YEC may be required to carry out in order to commence construction on other projects before 2016 to meet the needs of potential major industrial customers or other major potential developments in Yukon.

The Final Argument includes the following major parts:

1. Part A: Near Term Proposed Projects of $3 million or More
2. Part B: Planning Activities to Meet Longer-term Industrial Opportunities
3. Part C: Other Issues Addressed by Participants

[7] For example the YESAB filing related to Carmacks-Stewart project environmental and socio-economic regulatory review (Exhibit B-13) and the Update filing related to this same project as well as the Marsh Lake and Mirrlees projects (Exhibit B-16)

To the extent that the Board and intervenors examined specific issues on the above matters, Yukon Energy has attempted in this argument to address the apparent concerns raised. In the view of Yukon Energy, its filings, interrogatories and other evidence submitted (including undertakings) fully address all such concerns, fully support the reasonableness and need for the proposed major spending commitments, and no evidence-based contrary position has been tendered by any party.

2.0 PART A: NEAR TERM PROPOSED PROJECTS OF $3 MILLION OR MORE

Part A address as the Board's mandate to review those projects related to the Plan which require commitments by Yukon Energy before the year 2009 for major investments with anticipated costs of $3 million or more.

The Minister directs the Board's review address the necessity of the proposed project spending commitments and, to the extent currently known, their physical and engineering characteristics and their economic consequences with emphasis on four specific matters. Based on the specific considerations identified by the Minister in his June 5th letter this argument reviews in detail the following matters for each of the three proposed near term projects in the Plan with anticipated costs of $3 million or more:

- Overview of Proposed Projects – Physical and Engineering Characteristics
- Need for the Proposed Projects - Capacity Planning Criteria and Capability of Existing Facilities
- Need for the Proposed Projects - Load Forecast Requirements
- Economic Consequences - Options and Selection on Reasonable Grounds
- Economic Consequences – Risks
- Effects on Rates
- Other Potential Near Term Projects

2.1 OVERVIEW OF PROPOSED PROJECTS – PHYSICAL AND ENGINEERING CHARACTERISTICS

The Plan as updated in Exhibit B-16 proposes for YUB review three generation and transmission capital projects which require commitments by Yukon Energy before the year 2009 for investments of $3 million or more[8], namely:

- the Mirrlees Life Extension Project to address WAF capacity shortfalls,
- the Aishihik 3rd Turbine Project offering opportunities to displace WAF diesel generation, and
- the Carmacks-Stewart Transmission Project offering opportunities to sell near term surplus hydro power to new mines and to connect the two grids for long-term efficiencies.

A brief summary is provided below of each of these proposed near term projects, including review of their physical and engineering characteristics.

[8] Yukon Energy's updated Plan (Exhibit B-16) no longer includes any plans to proceed with the Marsh Lake Fall/Winter Storage Project (see section 2.7.1 below); even when this project was included, it was not expected to involve cost commitments of $3 million or more.

2.1.1 Mirrlees Life Extension Project

The updated Mirrlees Life Extension Project (Exhibit B-16) provides for 12,000 hour overhauls and related diesel plant upgrades (as described in Exhibit B-3, Tab 1[9]) to proceed over three years for the three Mirrlees units at the Whitehorse Diesel Plant (total of 14 MW at an estimated overall cost (2005$) of $6.4 million) and one Mirrlees unit at the Faro Diesel Plant (5 MW at estimated cost (2005$) of $2.3 million)[10]. As a result of the decision to proceed with a Faro-focused option in 2007, the Whitehorse Mirrlees Life Extension will now follow in 2008, 2009 and 2010 (a staged approach with one unit each year, starting with WD3).

Absent this Life Extension Project, the three Whitehorse Mirrlees units (with a combined current capacity rating of 11.4 MW) would be retired by 2011 (Exhibit B-2, page 16), and as a result under YEC's new capacity planning criteria, each of these retirements would directly add to the WAF capacity planning shortfall. Because the Faro Mirrlees unit is currently retired; rehabilitation of this unit (or any equivalent alternative involving installation at Faro of used units) will add to WAF system capacity.

The rehabilitated Mirrlees units are planned to provide cost-effective and reliable backup capacity for the WAF grid related to the Aishihik transmission line, and not to operate as baseload or even regular peaking units.[11] The Mirrlees units have never been high in Yukon Energy's diesel stacking order. [12] Although these units are currently ranked on YEC's WAF stacking order at 3.7 kWh per litre of light fuel use and overhauling the units will increase the fuel efficiency to around 3.9 kWh/litre which is close to what YEC will get with a brand-new unit of any manufacturer (Campbell, transcript page 466, lines 14 to 22).[13]

The Plan has noted throughout the extreme importance of timing. The initial Mirrlees unit is required to be available for the winter of 2007-2008. Further there is need to secure the other units as planned in subsequent years, in order to meet WAF capacity planning requirements.

It is important to note that rehabilitation of the Mirrlees units does not require special environmental assessment and/or licensing to proceed, nor does it require any specific approvals from the Minister responsible for YDC. Further Yukon Energy has recently undertaken extensive due diligence which has confirmed the capability to successfully complete the Mirrlees Life Extension Project in the time frame required (Exhibit B-3, Tab 1; Exhibit B-16, section 3; Morrison, transcript page 234, line 24 to page 237, line 16; also Morrison, transcript page 534 line 21 to page 536, line 17 on work done since the NTPC

[9] These upgrades include addressing cooling system issues in the plant (see response to question from Mr. Phillips, transcript page 504, line 7 to page 505, line 3).

[10] Exhibit B-16, section 3, reviews the rational for the new Faro-focused option and notes that YEC will consider for the Faro-focused option other "used" unit alternatives where they are cost competitive and offer other advantages, e.g., a possible option to secure two EMD 645F4B 2.8 MW units for installation as an alternative to the Mirrlees rehabilitation is noted.

[11] Mr. Morrison reviewed this with Mr. Buonaguro at transcript page 235, line 3 to page 237, line 16, noting that these units may run 100 to 200 hours per year on average in a back-up capacity. See also Morrison, transcript page 467, lines 2 to 10 and page 469, lines 2 to 19; Osler, transcript page 467, line 11 to page 468, line 13; and Bowman, transcript, page 469, line 20 to page 470, line 7. See also response to YCS-YEC-2-10(f).

[12] Mr. Campbell, transcript page 468, lines 14-21; also Exhibit B-23 on WAF Dispatch Table and related remarks at page 515, line 10 to page 516, line 17.

[13] The Whitehorse Mirrlees units all ran as expected in response to the January 29, 2006 WAF blackout (Morrison, transcript page 536, lines 22 to 25)

report involving technical external advisors). As part of Yukon Energy's due diligence, issues raised in the 2004 NTPC report (UCG-YEC-1-42, Attachment 1) regarding the Whitehorse Mirrlees units were specifically reviewed in detail.[14]

2.1.2 Aishihik 3rd Turbine Project

The Aishihik 3rd Turbine is an enhancement opportunity to provide 7 MW of added WAF peaking capability and about 5.4 GW.h/yr of added WAF long-term average hydro energy supply at the existing Aishihik generation station. This enhancement will displace WAF diesel generation at a capital cost of about $7 million (2005$).

Although Yukon Territorial Water Board and environmental approvals for the project were received in the new Aishihik Water Licence[15], the project will still require approximately 24 months from a decision to proceed until in-service.[16] The Plan proposes to complete the planning process as needed to enable a final decision during 2007 which will allow construction to start in time for an in-service date of October 2009. Provision is also made to delay construction until 2009 and in-service until 2011 if warranted (in response to timing of other projects and/or WAF load growth) (Exhibit B-2, pages 27 to 28).

The Plan provides economic assessments of the Aishihik 3rd Turbine Project confirming its economic feasibility within the planning period to 2025 based solely on its diesel operating cost saving benefits for the WAF grid, including displacement of peaking and then baseload diesel as WAF loads increase (Exhibit B-1, Appendix C). Based on the update (Exhibit B-16), Yukon Energy expects to start construction in 2007 for in-service in 2009 given the combined effects of not proceeding with Marsh Lake Fall/Winter Storage and proceeding with only Stage 1 development of the Carmacks Stewart Project (each of which improves the economics of the Aishihik 3rd Turbine).

Based on the new capacity planning criteria, unless the Aishihik 2nd transmission line project is undertaken, the Aishihik 3rd Turbine will not currently contribute any addition to WAF peak winter capacity; although it could provide about 0.6 MW of new WAF peak winter capacity if sufficient industrial loads are on WAF such that the LOLE criterion drives capacity planning requirements (e.g., if both the Minto and Carmacks Copper mines are being served). In the event that the Aishihik 2nd Transmission Line Project is developed in the future, the full Aishihik 3rd Turbine capacity would be captured for WAF capacity planning needs.

The Aishihik 3rd Turbine Project is not linked to Aishihik rewind projects, nor is timing of this project expected to be affected by Aishihik unit re-runnering plans (Bowman and Campbell, transcript page 485, line 12 to page 487, line 26).

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[14] Yukon Energy in the hearing in response to questions from both Mr. Buonaguro (transcript, page 232, line 23 to page 239, line 2) and Ms. Marx (page 465, line 6 to page 478, line 25), including (in addition to matters addressed above):

- Clarification that these units are not (as suggested in the NTPC report) "a continuous environmental liability", i.e., all oil leaked from these engines is contained within the diesel plant (transcript page 237, line 21 to 26; page 470, lines 8 to 25);
- These units do require a high degree of attention when running as they basically need an operator at the plant (which occurs in any event at the Whitehorse Diesel Plant) (transcript page 475, line 7 to page 476, line 19).

[15] See Campbell, transcript page 226, line 17 to page 227, line 26.

[16] See Campbell, transcript page 488, lines 8 to 22.

2.1.3 Carmacks-Stewart Transmission Project

The Carmacks-Stewart Transmission Project is an enhancement opportunity which, when fully developed in Stage 2, will interconnect the Mayo Dawson (MD) and WAF grids with 138 kV facilities (approximate length of 172 km) in order to provide long-term system efficiencies and enhanced economic development opportunities in the project area. Stage 1 development is planned to extend the WAF grid at 138 kV from Carmacks to Pelly Crossing (approximate length of 98 km) by the third quarter of 2008, providing WAF surplus hydro to displace diesel generation at both the Minto mine (through an additional 35 kV spur line of about 27 km length) and at Pelly Crossing. The project includes new substations facilities at Carmacks and Pelly Crossing, and expansion of the existing MD substation facilities at Stewart Crossing.

Since the June filing of the Plan, Yukon Energy has carried out extensive consultations with the Northern Tutchone First Nations and others and has filed its YESAB application which includes detailed description of the project and the selected route (Exhibit B-13 - summary of key points, including current project schedule, in Exhibit B-16, section 4). Further, as reviewed in the update (Exhibit B-16), a number of very positive developments have occurred in relation to the Minto mine, i.e., the mine owners have now received the $85 million of debt financing needed to complete the mine which is now more than one-third built and scheduled to start production in the second quarter of 2007 using on-site diesel generation with expected power requirements by year 2 of operation at 32.5 GWh/year (well above earlier forecasts of 14 GWh/yr in Exhibit B-1 and 24.5 GWh/yr in Exhibit B-3, Tab 2) .

Yukon Energy has provided updated economic assessments of this project (Exhibits B-16 and B-22) to reflect updated capital cost (2005$) estimates, with mid point updated cost estimates of $20.2 million for Stage 1 and $35.4 million for the full Stage 1 and Stage 2 development[17], as well as a YDC contribution of approximately $5 million (reflecting the value of increased payments to YDC under the Flexible Term Note ("FTN")) and estimated potential net ratepayer benefits under stipulated assumptions.[18]

[17] The update provides a range of potential line-related capital cost estimates (2005$) to reflect uncertainties regarding the impact of tight labour market conditions in Western Canada and other factors (e.g., raw material cost increases), based on reviews of recent YEC cost experience and also discussions in August with engineering consulting firms leading to securing expression of interest to submit proposals on the upcoming RFP for engineering services for this project. Yukon Energy submits that it has addressed uncertainty with regard to such cost estimates (an issue raised in YECL's withdrawal letter, Exhibit C1-5) to the extent feasible prior to completion of final design and costing, and potentially prior to completion of actual tendering. The update also provided estimates of likely escalation of Stage 1 costs by 10% to 15% from 2005$ to final in-service costs.

[18] As reviewed in Exhibit B-22, net ratepayer benefits in Stage 1 reflect use of WAF hydro resources at Pelly Crossing and the Minto mine. Stage 2 development to connect the two grids in combination with a Carmacks Copper mine connection would potentially provide added net ratepayer benefits associated with Carmacks Copper power use and access to surplus MD hydro generation (up to 15 GWh/yr in 2012) plus surplus MD diesel capacity (up to 5.6 MW in 2012); however, ratepayer benefits associated with Stage 2 are subject to the assumption of surplus generation resources on MD, which would not be available to the extent that new industrial development (e.g., UKHM) occurs concurrently on the MD system. (Osler, transcript page 253, lines 4 to 14: "The thing we are most worried about, at that stage [bring on Carmacks Copper and proceed with Stage 2], is whether or not the energy that we are assuming is there from Mayo-Dawson is really there, or whether there are some things happening up in Mayo-Dawson that have used that energy for some other purposes, such as United Keno Hill Mine." Also Osler, transcript page 240, lines 15 to 25 and page 245, line 24 to page 246, line 6.) Without new near-term hydro energy generation supplies assumed in the Plan from MD as well as Aishihik 3rd Turbine (and Marsh Lake in the initial Plan), the Plan indicates that serving both Minto and Carmacks Copper mines would lead to new baseload WAF diesel generation even at earlier lower Minto mine loads (see references to Appendix C, Exhibit B-1: transcript, Bowman notes new diesel of up to 40 GWh/yr by 2016 at page 56, lines 14 to 18; Osler references specific tables in Appendix C for review at page 513, line 11 to page 514, line 3).

The update (Exhibit B-16) did not include provision for any net capital contribution from the Minto and/or Carmacks Copper mines in order not to involve any presumption about the outcomes of PPA negotiations; however, Yukon Energy has made it clear that a material net capital cost contribution will be required from each mine connecting to this project.[19] Without providing for such net capital contributions from any mines, the update (Exhibit B-22) indicated that Stage 1 development with only the Minto mine and without any YTG funding would yield benefits overall stage 1 net benefits (costs) of approximately zero, i.e. the ratepayer benefits in effect are sufficient to offset the mid-point capital cost estimate.

As reviewed in Exhibit B-16, a signed Power Purchase Agreement (PPA) will be required by Yukon Energy with the Minto mine before proceeding with construction of Stage 1; the PPA will be provided to the YUB as soon as it is available. The principles regarding any power rate charge to each mine, and the requirement for YUB approval of any such rate, were reviewed in the hearing.[20] Contrary to the concerns raised in the YECL withdrawal letter (Exhibit C1-5) as to uncertainty about the appropriate industrial rate, industrial investment policy, and customer contribution, the evidence in the hearing has clearly set out YEC's understandings and requirements on these matters such that nothing more can be examined until a signed PPA is tabled with the YUB for its review. In this regard, Yukon Energy notes that review of industrial rates and customer contributions is clearly within the mandate of the Board under the Act.

During the hearing Yukon Energy clarified the basis under which it may, as part of the PPA, acquire control of 6.4 MW of high speed diesels at the Minto mine site that will be surplus to the mine's needs after YEC starts delivery of grid power. Any such arrangement would involve YEC ownership and control of the units, and not an IPP type of arrangement.[21]

Stage 1 development of this project is very sensitive to timing considerations. The sooner that Stage 1 of this project is built and can start delivery of power to the Minto mine, the sooner and longer that ratepayers can capture the benefits of these new firm sales of surplus WAF hydro generation over the limited life of this mine (Exhibit B-22, Schedule 2 indicates Minto mine revenue ratepayer benefits lost for each month of delay are more than $200,000 per month based on an assumed net rate of 7.6 cents per kWh after deduction of FTN cost at 1.7 cents). It is also apparent, based on the LOI and other considerations, that grid power delivery needs to occur no later than by about the end of 2008 in order to secure sufficient benefits for both the mine and all ratepayers under current firm mine life assumptions[22].

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[19] See Osler, transcript page 257, line 16 to page 259, line 19 where the general principle is set out that mines will be required to provide a positive present value contribution to the construction cost of the Carmacks-Stewart line over and above paying fully for any spur lines to each mine from the Carmacks-Stewart line; this point was re-iterated at transcript page 502, line 19 to page 503, line 22. The earlier Letter of Intent (LOI) principles with Minto in this regard were reviewed by Mr. Osler with Mr. Buonaguro, along with the Minto Feasibility Study outcomes indicating significant positive net savings for Minto (with adoption of the LOI contributions to YEC) of $19 million present value which YEC has updated to $15 million present value based on Exhibit B-16 updated cost and load assumptions (transcript page 260, line 3 to page 261, line 24); this matter was also reviewed by Mr. Osler at page 501, line 13 to page 502, line 18 - note correction filed on November 22, 2006 re: line 11 at page 502.)

[20] It was confirmed that the contemplated rate would be a firm rate and not subject to terms similar to a secondary energy rate (Morrison, transcript page 281, line 9 to page 282, line 16). Discussion with Mr. Pinard as to definition of major industrial customer based on OIC 1995/90 and need for YUB approval (Osler, transcript page 82, line 13 to page 83, line 11; page 84, lines 5 to 24). Discussion with Mr. Buonaguro as to industrial customers and related industrial rates, riders applicable to such rates, need for and likely outcome of updates to Rate 39 and other related matters (Osler, transcript page 111, line 2 to page 124, line 19).

[21] See discussion with Mr. Pinard (transcript page 96, line 1 to page 97, line 22); discussion with Mr. Buonaguro, (transcript page 265, line 24 to page 269, line 7).

[22] Osler, transcript page 263, line 18 to page 264, line 3.

The current schedule as set out in Exhibit B-16 assumes, in order to achieve in-service in quarter 3 of 2008, that construction must be able to start as soon in fall 2007 as all approvals are secured.

2.2 NEED FOR THE PROPOSED PROJECTS - CAPACITY PLANNING CRITERIA AND CAPABILITY OF EXISITING FACILITIES

Over half of the need for new WAF firm winter capacity in the near term (between now and 2012) as set out in the Plan, which provides the basis for the proposed Mirrlees Life Extension Project, relates to adoption of new capacity planning criteria and scheduled retirement of existing Mirrlees diesel units at Whitehorse. The capability of WAF systems to provide significant surplus hydro electric generation over at least the next 15 years under expected non-industrial load growth provides the near term opportunity to support Stage 1 development of the Carmacks-Stewart Transmission Project to connect the Minto mine and Pelly Crossing to WAF; surplus hydro generation capability on the MD system could also potentially support Stage 2 of the same project to connect the WAF and MD grids and to supply the Carmacks Copper mine project.

Further to the Minister's direction to review need in the context of these matters, capability of existing facilities and the new capacity planning criteria are each reviewed below.

2.2.1 Capability of Existing Generation and Transmission Facilities

Limited questions arose during cross examination or interrogatories on the capability of existing facilities. The Plan's review is summarized below.

The Plan (Exhibit B-1 (Sections 2 and 3.1) and Exhibit B-2 (Sections 2 and 3.1)) reviews the condition of Yukon Energy's bulk electrical assets, indicating that, except for the three Mirrlees diesel units at the Whitehorse Diesel Plant, these assets are well suited to supplying future WAF and MD system load requirements. In contrast, the three Mirrlees diesel units (WD1, WD2, and WD3) are at "end-of-life" and, absent the Mirrlees Life Extension Project, are currently scheduled for retirement by 2011. No challenges were presented during the hearing as to these assessments.

The Plan also reviews the capacity and energy output capability of existing bulk electrical facilities on the WAF and MD systems (Exhibit B-1, Section 3.2) - including the firm (under low flow or drought conditions) winter capacity capability of the Whitehorse Rapids hydro facilities at 24 MW (out of 40 MW installed), the Aishihik hydro facility firm capacity and long-term average energy capability under the current Water Licence and different industrial load conditions, the Mayo hydro facility firm winter capacity and long term average energy capability, and the Fish Lake hydro (YECL) firm winter capacity (400 kW). The current de-rated maximum continuous rating of the current Whitehorse Mirrlees units was also noted (at 11.4 MW). Overall, existing WAF facilities are assessed to have the following capabilities during the 20-year planning period[23] (this assessment was not challenged during the hearing[24]):

[23] MD system firm winter peak capacity capability of 5.4 MW hydro and 7.3 MW diesel (Exhibit B-1, Table 2-1); long term average hydro generation capability is 42 GWh/year in a normal water year (Exhibit B-1, pages 3 to 10), of which about 17 GWh was surplus hydro energy as of 2005.

- Total WAF winter peak firm capacity capability of 87 MW (see Exhibit B-2, page 18), less retirements of the Mirrlees Whitehorse diesel units as scheduled from 2007 through 2011.
- WAF system long-term average hydro energy capability of about 358 GWh/yr in a normal water year (Exhibit B-1, pages 4 to 13; Exhibit B-2, page 11), of which the Plan notes that about 90 GWh was surplus hydro energy as of 2005 (a portion of which was supplying secondary sales).

2.2.2 Generation Capacity Planning Criteria

Generation capacity planning criteria are the sets of rules used to determine how much generation capacity is required on the various Yukon systems and when additions to generation capacity are required (Exhibit B-2, page 17). Reflecting evolving capacity planning at other utilities as well as concerns about the adequacy of the previous YEC criteria (as last reviewed by the YUB in 1992) to provide reliable service at Whitehorse[25], Yukon Energy in 2004 and 2005 undertook an extensive review of capacity planning criteria for its Yukon systems.

As a result of this review, Yukon Energy adopted in December 2005 the Loss of Load Expectation ("LOLE") approach (with planned capability not to exceed an LOLE of 2 hours per year), with recognition of transmission reliability where relevant to generation supply, as part of its system generation capacity planning criteria for the WAF and MD grids to better protect customers from having inadequate amounts of generation available. Further, in order to address the severity of a potential outage due to insufficient available generation, Yukon Energy also adopted a second test (the "N-1" standard) as part of its generation capacity planning criteria for the WAF and MD systems to ensure there is sufficient generation installed to meet firm residential and commercial customer loads (i.e., loads that typically do not have their own emergency backup generation) when a failure occurs to the single largest system generation or transmission-related-generation component. In the case of WAF, this largest single most critical system component is currently the Aishihik transmission line connection between Aishihik generation and the Whitehorse bus. Subsequent to preparing the initial Plan, Yukon Energy on January 29, 2006 experienced a power outage on the WAF grid due to a failure on the connection to the Aishihik generation (Exhibit B-25 reviews information on this outage).

Extensive questioning during the hearing of Dr. Billinton and other members of YEC's panel, as well as numerous interrogatories, addressed detailed review of Yukon Energy's new generation capacity planning criteria. Attachment A reviews the evidence on the matters raised by participants with regard to Yukon Energy's capacity planning criteria, including the following four specific issues arising from cross-examination:

- The potential use of an energy-based criteria (such as LOEE) instead of the LOLE criteria. (The evidence establishes that energy-based measures such as LOEE are not as appropriate

[24] Questions were raised about potential for a project to enhance Whitehorse Hydro firm winter capacity through outcomes of current downstream icing studies. This concept, which reflects an enhancement proposal for existing capabilities, is addressed under longer-term project options below (Part 2).

[25] YEC noted in the 2005 Application to the YUB that application of the old criteria was indicating WAF generation was still adequate even if only 36 MW installed in Whitehorse (after Mirrlees retirement) in the context of a local winter peak of 46.7 MW. YEC noted that a similar situation did not occur anywhere else for major loads on the integrated grids.

criteria for Yukon as those adopted by YEC – and involve increased complexity, more limited ability to readily compare standards with other jurisdictions, and limited additional value (if any) in terms of determining the optimum system expansion plan required at any one time.);

- The need for two criteria, particularly in light of the N-1 criteria being the dominant criterion during the planning period. (The evidence of both Dr. Billinton and Mr. Morrison clearly indicate that lack of an N-1 criteria would not be appropriate for Yukon, would not be consistent with other jurisdictions including NWT and utilities throughout North America, and would not allow YEC to provide reliable electric power generation to meet the load forecast requirements particularly on the WAF system. The evidence also demonstrates that each criteria may be dominant for WAF during the planning period depending on industrial loads and/or resource plans developed, and that both criteria are therefore needed.);
- Data limitations and the use of Canadian Electricity Association (CEA) national data. (The evidence confirms that YEC will continue to be required to use CEA data on the forced outage and unavailability rates on generation and transmission units, which data is reasonable and provides the benefit of a much larger sample of units. YEC will continue to collect the required data to allow it to develop a dataset for future analysis as a comparison to the CEA data.);
- Peak periods only occurring for a short part of the year. (The evidence provides no basis for establishing an N-1 criteria at any level below the full forecast peak load level – NWT experience if anything might suggest a basis for adopting a slightly higher level above the full forecast peak.).

With regard to the N-1 criterion for WAF, Yukon Energy notes that the specific factor likely responsible for the January 29, 2006 Aishihik connection failure (fault in underground feeder cables at Aishihik) represents only one of many potential sources of failure that could result in this N-1 event. For example, the Aishihik line is 140 km long with about 700 structures each having three insulators (about 2,100 insulators or potential points of failure). Any such failure will, due to its magnitude, in almost all cases result in an outage on WAF regardless of the capacity planning criteria adopted (transcript, page 449, line 25 to page 450, line 17)[26]. Absent an N-1 criterion, there are substantial concerns about the ability to recover from such an outage or to avoid lengthy periods of rolling blackouts in the event the failure happens during the peak winter periods of very cold weather[27] (transcript page 538 line 13 to page 541, line 8).

In summary, in response to the Minister's specific directions, the evidence clearly establishes that the new capacity planning criteria adopted by Yukon Energy for the WAF and MD systems are appropriate and adequate to establish requirements for electrical power generation capacity for these systems in accordance with principles established in Canada by regulatory authorities regulating hydro and non-hydro electric utilities. As stated by Dr. Billinton, a recognized international expert on these matters (transcript page 75, lines 1 to 9) when asked, in his view, is the new criteria reasonable particularly in light of similar planning criteria used elsewhere in Canada:

[26] The only resource option that could prevent such an outage related to a loss of this line would be the Aishihik twinning option.
[27] Limited available hours of daily light conditions during peak winter conditions can also affect the ability to find a fault and restore the line on a timely basis.

> "Yes, I think it is quite reasonable. It is understandable and straightforward. It lies, I think, in the range of planning criteria that are used elsewhere in Canada. And it, of course, relates directly to the criteria that are being adopted in the Northwest Territories for a very similar system. So, therefore, I think it provides a very practical and reasonable framework upon which to conduct adequacy evaluation."

2.3 NEED FOR THE PROPOSED PROJECTS - LOAD FORECAST REQUIREMENTS

Electrical load forecast requirements for WAF, including requirements related to potential new major industrial customers (the Minto mine and potentially the Carmacks Copper mine), establish the need for new firm winter capacity in the near term by 2012 beyond that required solely to address Mirrlees diesel unit retirements. These forecast requirements also establish the need, particularly with new mine loads, for near term system enhancement opportunities to provide additional hydro electric energy to displace peaking and baseload diesel generation on WAF.

The Plan forecasts Base Case WAF load requirements with these mine loads resulting in WAF capacity shortfalls of 0.7 MW in 2006, 15.3 MW in 2009 and 21.5 MW in 2012 (Exhibit B-2, page 25); without these mine loads, the Base Case load forecast capacity shortfall in 2012 is 18.7 MW while the Low Sensitivity Case load forecast capacity shortfall in 2012 is 14.7 MW. The following conclusions with regard to WAF capacity needs are confirmed by the evidence:

- Regardless of the load forecasts reviewed, the Plan confirms the need for the Mirrlees Life Extension Project with the likely need for all four units and 19 MW of new capacity by 2012.
- Depending on actual load growth, the Plan estimates that new capacity requirements by 2012 could range up to 21.5 to 26.7 MW (with updates suggesting higher potential needs), indicating the need for other new WAF capacity in the near term beyond the Mirrlees Life Extension Project[28].
- The Carmacks-Stewart Transmission Project, if fully developed with the Stage 2 connection of the WAF and MD grids, could potentially provide 5.6 MW of added capacity by winter 2009/2010 and thereby address a capacity shortfall of about 23.5 MW associated with the updated Base Case with Mines forecast – however, this potential is subject to many risks, including the risk that UKHM mine loads may return to the MD grid during this period.
- Absent an Aishihik 2nd Transmission Project, the Aishihik 3rd Turbine will not materially address the need for additional WAF firm winter capacity beyond that provided by the Mirrlees Life Extension.
- Contingency options to provide additional WAF capacity if needed in the near term include YEC acquiring surplus used diesel units (6.4 MW) at the Minto mine site (after the start of delivery of grid power to the mine), twinning of the Aishihik line, and increasing the MW density of the Whitehorse Diesel Plant (Exhibit B-7, slide 32 and Osler, transcript page 63, line 9 to page 65, line 1).

[28] Updated mine load forecasts likely raise these potential shortfalls. Mine loads do not affect the N-1 criteria, but do affect the LOLE criteria assessment – as a result, the first 6.2 MW of new industrial WAF load (an amount less than the Minto mine load as currently forecast) does not drive new capacity requirements (Exhibit B-1, pages 4 to 12). The updated Minto mine load and Carmacks Copper mine load combined, however, is now about 11 MW, or about 2 MW higher than the level assumed in the Plan, i.e., the overall Base Case with Mines capacity shortfall for 2012 would now approximate 23.5 MW rather than the 21.5 MW in the Plan.

The Plan forecasts electrical energy requirements on WAF with the Base Case and Mine Loads (under the earlier much lower Minto loads of only 14 GWh/yr rather than the current 32.5 GWh/year) such that, during the time when both mine loads are being served, all WAF surplus hydro would be fully absorbed, WAF secondary energy sales would be fully curtailed, and modest baseload diesel generation would be required.[29] The following conclusions with regard to WAF hydro energy needs are confirmed by the evidence:

- Forecast WAF load requirements with the Minto mine connection (Stage 1 of Carmacks Stewart Transmission) provide the need to develop the Aishihik 3rd Turbine by 2009 to help displace near term peaking diesel generation costs and to provide for added hydro baseload generation in the event that more mine loads are added to WAF and/or after 2020 when WAF baseload diesel generation needs are forecast under Base Case forecasts in any event.
- In the event that both mines are connected in the near term, the Carmacks-Stewart Transmission Project, if fully developed with the Stage 2 connection of the WAF and MD grids, could potentially provide about 15 GWh/yr of added hydro energy by winter 2009/2010 and thereby address forecast hydro generation shortfalls with the updated Base Case with Mines forecast – however, this potential is subject to many risks, including the risk that UKHM mine loads may return to the MD grid during this period.
- In the event that both mines are connected in the near term, and Stage 2 of Carmacks Stewart cannot provide the needed additional hydro energy, Yukon Energy would pursue other proposed actions set out in the Plan (Exhibit B-2, page 45, section 5.5.1 and Exhibit B-1, page 5-32, section 5.5.1 sets out potential consideration of the smallest hydro site options (1-4 MW) as well further consideration to DSM programming).

Load forecast issues were reviewed in interrogatories and in cross examination during the hearing. Attachment B reviews the evidence on the matters raised by participants with regard to Yukon Energy's non-industrial WAF load forecasts, including the following specific issues:

- Extent by which load forecasts drive the proposed projects and actions in the Plan - overall, the evidence shows that the Plan's non-industrial load forecasts have only a small impact on the projects and actions proposed in the Plan.
- WAF load growth trends updated – As reviewed with UCG counsel, Exhibit B-18[30] reviewed the methods used in the Plan (Exhibit B-2, page 24) to assess WAF non-industrial wholesales growth rates at 2.2%/yr average between 2001 and 2004, and updated this for the most recent three year average to 2006 (indicating an increase in this average annual growth rate from 2.2% to 2.6%). In summary, updated evidence provided no basis for suggesting a lower growth rate than the 1.85 %/yr assumed in the Plan's Base Case for non-industrial WAF loads.
- WAF winter peak loads - Exhibit B-20[31] reviewed the methods used to assess winter peak loads on WAF, as well as updated data on WAF peak loads since the Plan was prepared. In summary, taking into account the need to exclude secondary sales and to consider likely

[29] Exhibit B-2, page 25; Exhibit-B-1, pages 4 to 13 as well as Appendix C, Section C.3.
[30] Bowman, transcript page 216, line 26 to page 221, line 3.
[31] Campbell transcript page 273, line 21 to page 277, line 8.

peak loads to below -40 deg C, the latest 2006 data confirm a likely current peak 2006 winter WAF load for planning purposes (i.e., assuming temperatures of -44 deg C) of about 57.5 MW (which is within 0.1 MW of the Plan's forecast 2006 peak load).

- Commercial and residential Whitehorse growth estimates - Mr. Morrison reviewed Whitehorse commercial growth with Ms. Marx (page 318, line 9 to page 324, line 11), and set out the key support for the related Whitehorse load forecast, addressing some of the related issues raised in the YECL withdrawal letter (Exhibit C1-5); he also reviewed Whitehorse residential growth experience in response to a question from Mr. Morris (transcript page 505, line 15 to page 506, line 3). Mr. Maissan raised concerns about the impacts of electric heating load growth not accounted for in YEC's forecasts (transcript page 416, line 24 to page 417, line 15).
- YECL's withdrawal letter (Exhibit C1-5) raised four factors in support of its general assertion that the YEC load forecast continuing at 1.85% was "overly optimistic". These issues are each reviewed in Attachment B, along with the evidence contained in Exhibit B-19 which highlights YECL's consistent tendency to underestimate WAF wholesale loads in forecasts provided to YEC in recent years. In summary, the load forecast matters raised by YECL have no evidentiary support in this hearing and do not effectively challenge or undermine any of the relevant and evidence-based support Yukon Energy has provided for the non-industrial WAF load forecasts set out in the Plan.

In summary, in response to the Minister's directions, the available load forecast requirements evidence provides a solid basis for establishing the need for Yukon Energy to proceed with the three near term proposed projects with cost commitments before 2009 of $3 million or more.

2.4 ECONOMIC CONSEQUENCES - OPTIONS AND SELECTION ON REASONABLE GROUNDS

The Plan and related evidence filed by Yukon Energy during the current YUB proceeding confirm that all reasonable alternative options have been considered and that the three proposed major near term project spending commitments have been selected on reasonable grounds that include technical feasibility, cost efficiency and reliability (see above sections 2.1 through 2.3).

In this regard, the Plan focuses considerable attention on seeking to match load requirements with available resource supply options. The selected options are each technically feasible, address specific load needs and opportunities, are cost efficient relative to other options considered, and are reliable with regard to the supply roles assumed in each instance.

During the current proceedings questions have been raised as to why certain other options were not selected or retained as part of the near term proposed projects, including DSM, the Aishihik 2nd transmission line, Marsh Lake Fall/Winter Storage and downstream icing mitigation and other related measures to enhance the Whitehorse hydro plant firm winter peaking capacity. Yukon Energy notes that all of the identified options were in fact considered. The factors affecting each project option not included in the near term proposals are reviewed below in section 2.7 or part B of this Final Argument.

One other related issue raised during the current proceeding was the extent to which Yukon Energy had considered sequencing options for its three proposed near term projects.
In Figure 4.15 (pages 4 to 54) of the Plan (Exhibit B-1) Yukon Energy provides its then proposed optimal sequence of the proposed major near term projects. The primary driving factor in this analysis is the timing to in-service-date ("ISD") required to develop each respective project.

Below is a brief summary of the reasons behind the sequencing in Figure 4.15 (for more detail see YUB-YEC-1-10; the analysis excludes Marsh Lake based on Exhibit B-16):

- The Mirrlees Life Extension can only practically be scheduled for one unit per year, starting in 2007 (and there is no apparent benefit in trying to proceed any faster with these units); further, as reviewed in Exhibit B-16, Yukon Energy has set out its reasons for proceeding with the Faro unit first.
- The Aishihik 3rd Turbine project provides only limited firm capacity benefits – the project is instead being pursued for peaking energy benefits (to offset winter peaking diesel requirements as the load on the system grows). This project is not proposed until the third quarter of 2009 or perhaps as late as 2011 or 2012 (once load development has occurred to ensure sufficient peaking diesel use can be offset by the unit). Minto mine connection by late 2008 will likely provide the basis for a 2009 ISD for this project.
- The Carmacks-Stewart transmission line cannot be practically licenced and constructed for full in-service (Stage 2 in addition to Stage 1) any sooner than the third quarter of 2009 (per Supplemental Filing Tab 3, as compared to third quarter 2008 in the initial Plan, Exhibit B-1). Updates (Exhibit B-16) set out in detail the fastest possible schedule for Stage 1 development with the earliest ISD being in quarter 3 of 2008; the timing of development of Stage 2 is also noted to be affected by many risk factors, including confirmation of Carmacks Copper mine operation and grid connection, the absence of UKHM reopening on MD, and continuing likely need for some levels of YTG funding to ensure no adverse rate impacts from Stage 2 development.

Under cross examination by the Board counsel (transcript page 453, line 10 to page 456, line 22) the only sequencing issue raised was concern that only one sequence was considered. Yukon Energy explained that in reality, after review, it was concluded that only limited sequencing options were available due to the nature of the system, expected shortfalls, and timing required to implement various project. Mr. Osler stated the following:

> "In larger systems, you would look at a varied sequence analysis and, in that sense, it would appear we did not do it, if you put it simply. On the other hand, working on the projects, I can tell you, we went though all sorts of sequences gyrations over the last year and a half, at a level that I would not want to bore you with going through the details."(transcript page 455, line 16 to line 23)

No party has called evidence to oppose the sequencing proposed in the Plan. In addition, the evidence before the Board in this proceeding demonstrates that Yukon Energy has done its due diligence in matching expected future loads with required capacity and energy when selecting the three major projects proposed in the near term.

2.5 ECONOMIC CONSEQUENCES – RISKS

Yukon Energy's Plan has considered, with regard to each of the three proposed near term major projects, potential risks from all causes, including but not limited to economic and financial risks, and including possible modifications to design or schedule (and related effects on costs or benefits) from environmental review and related regulatory approvals.

Risks are reviewed separately below with regard to each of the three major near term proposed projects.

2.5.1 Mirrlees Life Extension Project

The Mirrlees Life Extension Project has been identified to face risks related to schedule and costs (due to uncertainties inherent in completing a 12,000 hour overhaul of these engines); no material risks are considered to be relevant in this instance with regard to environmental review or other regulatory approvals.

Considerable work has been carried out, as described in the evidence, to assess the technical risks as to YEC's ability to extend the life of these units as required for extended back up firm winter peak capacity service on WAF.

The sequence proposed for this project, starting with the Faro unit, along with due diligence assessments of other used unit options for the Faro facility, are steps adopted to mitigate and manage the relevant risks (particularly as to ensuring reliable capacity as needed is available for winter 2007/2008).

Economic and financial risks of possible cost overruns have been carefully assessed relative to other available options – and the proposed plan for Whitehorse Mirrlees Life Extension has been assessed to be a cost effective approach, even with these risks, relative to proceeding with new diesel units at this facility based on the expected back up role to be required of these units.

2.5.2 Aishihik 3rd Turbine Project

The Aishihik 3rd Turbine Project has the necessary licences and regulatory approvals, and is a new turbine to be installed in an existing facility. Technical risks related to carrying out this project are not expected to be material.

Potential cost overrun risks for this project will be managed by the tender process prior to any final decision to construct; load related benefit risks are being mitigated by careful assessment of the timing for a decision to proceed.

Minimal risk concerns are considered to apply in this instance with respect to schedule.

Benefits related to this project have been assessed based on the Plan's forecast cost of displaced peaking and baseload diesel generation. As reviewed during the hearing, the diesel price assumed in the Plan (at about 20 cents per kW.h in 2005$, with nominal 2%/year inflation) was based on forward oil price forecasts (2010, US$) of $50 to $55 per bbl; an update to this diesel price forecast today was noted to reflect a higher forward price (2010, US$) of about $65 per bbl (transcript page 462, line 24 to page 465, line 23), indicating the likelihood that updated benefit estimates for this project (assuming any specific mine load or non-industrial load forecast) would currently be higher than those indicated in the Plan. In addition, substantively increased Minto mine loads from those assumed in the initial Plan and development of Stage 1 of the Carmacks- Stewart Project (Exhibit B-16) would further enhance estimated benefits from this project in the near term. Non-industrial WAF load forecast risks which may also affect benefits for this project have been separately reviewed (see section 2.3 above), and updated evidence fully supports load forecast levels at least equal to those in the Plan forecasts.

2.5.3 Carmacks-Stewart Transmission Project

The Carmacks-Stewart Transmission Project involves a range of complexities and risks, including risks related to regulatory approval schedule delays with the new YESAB process, capital cost escalations due to tight construction and commodity markets, negotiation of PPAs with mines and a Project Agreement with the NTFN, security for any PPA arrangements that are made with mines, the timing and scope of any YUB process needed to review the PPA and/or the rates applicable to any mines, and specific risks related to the timing and magnitude of any net ratepayer benefits assumed to flow from Stage 2 connection of the grids.

Based on the application filed with YESAB (Exhibit B-13), YEC does not anticipate material risks of major design modifications resulting from the regulatory approvals and review process for this specific project - the major regulatory risk remains material delays in schedule which could adversely affect project costs and benefits.

Concerns have been raised during the current proceedings about Yukon Energy's project management skills to implement a project of this magnitude. In this regard, UCG's counsel reviewed with Yukon Energy specific issues and policy matters arising from the Auditor General's Report (Exhibit C-3-13) on the Mayo Dawson Transmission Project (transcript page 202 line 9 though page 208 line 21) and Yukon Energy has provided a copy of its contracting policies (Exhibit B-17).[32] Exhibit B-16 also sets out a project schedule which requires final design and tendering prior to a final YEC decision to proceed with the project, as well as separation of project design and construction contracts.

Concerns have been raised in these proceedings (e.g., Exhibit C1-5, the YECL withdrawal letter) with regard to both the accuracy of estimated capital costs for major projects in the Plan (due to current construction market conditions) and uncertainties related to industrial rates and industrial customer contributions. As reviewed above in section 2.1.3, the following are noted in this regard:

- The recent update (Exhibit B-16) provides a range of potential line-related capital cost estimates (2005$) to reflect uncertainties regarding the impact of tight labour market conditions in Western Canada and other factors (e.g., raw material cost increases), and Yukon Energy submits that it has addressed uncertainty with regard to such cost estimates to the extent feasible prior to completion of final design and costing, and potentially prior to completion of actual tendering.

[32] A copy of these policies and guidelines is available on YEC's web site and 13 of these polices were also provided in the 2005 hearing (transcript page 215, lines 8 to 20).

- Contrary to the concerns raised in the YECL withdrawal letter as to uncertainty about the appropriate industrial rate, industrial investment policy, and customer contribution, the evidence in the hearing has clearly set out YEC's understandings and requirements on these matters such that nothing more can be examined until a signed PPA is tabled with the YUB for its review. In this regard, Yukon Energy notes that review of industrial rates and customer contributions is clearly within the mandate of the Board under the Act.

Yukon Energy's Plan, as updated in Exhibit B-16 and reviewed in cross examination during the hearing, sets out the steps proposed to address the identified risks in an orderly manner (including proceeding in two defined stages) prior to any final decision to proceed with either Stage 1 or Stage 2 of this project. The next major step in this regard will be to conclude negotiation of a PPA with the Minto mine that will then be tabled with the YUB for its review; as reviewed in the hearing, this PPA is expected to address (among other considerations) the mine's responsibility for the spur line costs, the capital contribution that the mine will provide towards the Carmacks-Stewart line, the security that the mine will provide YEC with respect to these cost commitments as well as the level and life of its firm purchase power needs, and the provisions with respect to rates applicable to the mine.

2.5.4 Risks related to Part 3 Review

A regulatory schedule and cost risk not contemplated in the Plan is that one or more of the proposed near term projects will be subject to a Part 3 YUB review under the Act, as set out in the Minister's August 29th letter (Exhibit A-14).

The current YUB proceeding has resulted in a detailed and comprehensive review of YEC's proposed near term projects based on the information currently available. The information provided in this hearing is all of the information that can be reasonably expected prior to completion of various project-specific ongoing activities, egg. environmental review and regulatory approvals, final engineering design/costing/tendering, and conclusion of a signed PPA for specific mine customers.

Accordingly Yukon Energy believes that the Yukon Utilities Board has before it all of the necessary information and analysis to allow it to determine whether or not the proposed near-term projects are in the public interest. However, it is important to keep in mind that if for any reason the YUB is required to delay making that finding until all uncertainties in relation to each project are resolved, it is apparent that Yukon Energy will encounter material delays as well as added costs in proceeding with construction and in-service for these projects. The impact of such delays will vary depending on the specific project:

- Delays of the Mirrlees Life Extension could expose Whitehorse area WAF customers to serious reliability risks due to inadequate generation capacity to meet winter peaks.
- Delays of the Aishihik 3rd Turbine would simply defer YEC's ability to secure diesel generation cost savings.
- Delays of the Carmacks-Stewart Transmission Project would cost Yukon ratepayers for each month of lost Minto mine revenues (estimated at over $200,000 per month) and, under some severe conditions, could place the viability of the project at risk.

As far the delay risk related to a Part 3 review, Yukon Energy has no information as to any suggested timing for the OIC required to designate each project under the Act to be so reviewed, or how the scope for the YUB review in such a proceeding would materially differ from that directed with regard to these same projects in the current proceeding. If, as may appear to be suggested by Exhibit A-14, such processes will be initiated only after review of the YUB's report from the current proceeding, then the risk of serious schedule delays as noted above could clearly affect both the Mirrlees Life Extension Project and the Carmacks-Stewart Transmission Project.

Accordingly, Yukon Energy recommends that the Board address these concerns in its report.

2.6 EFFECTS ON RATES

The filed information reviews the effects of the various near-term projects on rates at section 4.4.4 of the Plan (Exhibit B-1) and updated for most near-term projects in Undertaking #12 (Exhibit B-24).

Rate impact considerations as they are addressed in resource planning are markedly different matters with respect to "opportunity" projects (Aishihik 3rd Turbine and Carmacks-Stewart) compared to "capacity-related" projects (Mirrlees Life Extension, or alternatives including an Aishihik 2nd Transmission Line or a Whitehorse Diesel Replacement/Expansion Project):

- **"Opportunity projects"** are pursued solely based on the ability to make the most of existing assets, and to have long-term beneficial impacts on ratepayers. In the event such positive rate benefits cannot be secured, these projects would not be pursued.
  - **Aishihik 3rd Turbine:** As set out in Appendix C of the Plan (Exhibit B-1), the Aishihik 3rd Turbine has positive rate impacts under all scenarios through the majority of its expected life. In particular, in each assessment case in that Appendix, the second table of analysis sets out the annual ratepayer impacts from the project[33]. Rate issues in regards to this project focus on the extent to which in the first few years of the project the annual "accounting costs" included in ratemaking might exceed the annual benefits, resulting in a short period of higher rates with the project than would have occurred without the project. This is further set out as follows:
    - o Undertaking #12 (Exhibit B-24) notes that under Base Case loads (no mines) and a 2009 in-service date, the project will result in an average 1.86% increase in rates at the date of in-service[34]. However, by 2020, this has progressed to a positive impact on rates (lower rates than would occur without the project) of 2.54%[35] and this beneficial impact will then only grow with time. Yukon Energy has noted, however, that in the absence of mine loads, the Aishihik 3rd Turbine project would not be

[33] The first table in each set focuses on overall project economics using effectively cash flows, while the second table looks at accounting costs as they would appear in Yukon Energy's revenue requirement for each year of the project, as compared to the benefits that would arise in each year.

[34] This is portrayed as approximately a $2.35 increase to the monthly bill of a residential non-government customer today using 1000 kW.h per month before government subsidies and before GST.

[35] Using simple assumptions, Undertaking #12 (Exhibit B-24) portrays this as a $3.21 decrease to the monthly bill of a residential non-government customer today using 1000 kW.h per month before government subsidies and before GST.

pursued for in-service until perhaps 2011-2012 to help mitigate this short-term rate impact in the very early years.

- Appendix C of the Plan (Exhibit B-1) reviews variations on the Base Case set out in Undertaking #12, indicating substantially enhanced rate benefits from the project in the event mine loads are developed (Table C-1 at page C-3, Exhibit B-1). In particular, the initial period of adverse rate impacts from the project drops from 8 years under Base Case assumptions to 2 years under the case with 10 MW of mine loads (as then assumed) and the overall lifetime NPV to ratepayers improves markedly.
- Since the materials in the Resource Plan were prepared, long-term diesel price forecasts have been markedly raised (transcript page 462, line 24 to page 465, line 23) increasing at 2010 from $55/bbl (2010$, US$) to $65/bbl (2010$, US$) which (along with higher expected Minto mine loads) will further aid in the beneficial rate impacts associated with the project.

– **Carmacks-Stewart:** Similar to the Aishihik 3rd Turbine, the Carmacks-Stewart project is proposed as an opportunity project; that is, the project will not be developed unless it has no adverse impact on existing ratepayers (transcript page 511 lines 13-20)[36]. Quantitatively presenting the rate impacts of the Carmacks-Stewart project under any set of assumptions is considerably more complicated to model and assess at the present time than the other projects proposed in the Resource Plan. This is for two reasons: 1) the project as proposed involves not only a comparison of YEC's costs with and without the project (such as was performed for the Aishihik 3rd Turbine in Appendix C of the Plan) but also revenues from selling otherwise surplus hydro to new mines at firm rates; and, 2) specific matters to do with the arrangements with the mines, including the amount of capital contribution the mines will make towards the Carmacks-Stewart project, remain under discussion and negotiation[37]. Further detail on the annual costs to ratepayers associated with the capital costs of a Carmacks-Stewart line are provided in Undertaking 8[38]; however it is not possible at this time to correspondingly provide in any meaningful way forecast annualized rate benefits from providing service to Minto and Carmacks Copper, nor to model the annualized rate benefits related to the Minto, Carmacks Copper or YDC contributions towards the project.

- **Capacity-Related Projects:** In contrast to the opportunity projects, there is a need at this time to invest relatively substantial sums in the WAF system in particular to ensure the system can meet forecast peak load requirements with the new capacity planning criteria. These projects will add required costs to the system, and will have impacts on rates. All options being considered require investment in capital assets, for facilities that will at most operate a relatively few hours per year (page 236 line 5-14). The key criteria for comparison

[36] With regard to residential customer rate impacts from this project, "It will be zero or negative, or it won't be developed" (transcript page 531, lines 2 to 3).

[37] However, note that the framework for discussion focuses on material contributions to the Carmacks-Stewart project as discussed at page 258, line 3 to page 259, line 18 of the transcript.

[38] filed November 22, 2006 but not yet assigned an Exhibit number; this exhibit ignored all factors that might offset these costs, including ratepayer benefits, YDC capital contributions, and mine contributions.

between the various options becomes weighing lower cost options against potential other non-rate benefits of options that are not the lowest cost:

- **Mirrlees Life Extension:** Through all review conducted by YEC, the Mirrlees Life Extension option has been highlighted as the lowest cost alternative to secure material new MW of WAF capacity. As noted in Undertaking #12 (Exhibit B-24), this option results in a maximum upwards rate driver of 2.62% at the time of carrying out the project, dropping over time as the investment depreciates. By comparison, the other major options to provide this capacity are markedly higher, as noted below.
- **Aishihik 2nd Transmission Line:** This project reflects capital cost estimates that are subject to considerable uncertainty similar to any transmission project prior to receipt of contract tenders. However, based on earlier \$16 to \$19 million cost estimates (2005\$), the rate impacts are at their maximum of 4.63% in the first years of the project, decreasing with time. Project benefits compared with the Mirrlees have been noted, including the increased benefits the project brings in the event further capacity is secured at Aishihik by way of re-runnering, and the increased ability to avoid system blackouts when there are outages of the existing Aishihik line. These other benefits are not readily reflected in rate impact assessments.
- **Whitehorse Diesel Replacement/Expansion Project:** The purchase of new diesel units for Whitehorse reflects costs per MW that are considerably higher than the Mirrlees Life Extension, with a maximum rate impact of 4.79% at the time of in-service for 18.7 MW (Exhibit B-24) decreasing with time as the units depreciate. Other than more modern standards, new diesels in Whitehorse are not expected to materially aid the system in terms of other rate-related variables (such as expected cost savings due to enhanced fuel efficiency[39]) or other qualitative benefits compared to the Mirrlees Life Extension project.

The other capacity-related contingency alternative discussed related to the 6.4 MW of high speed trailor mounted diesels at the Minto mine site, which will become surplus to Minto at the time of connection to the grid. YEC has indicated a potential (as part of PPA discussions) to purchase these units should the need arise, but no purchase terms have been confirmed so it is not possible to assess the relative rate impacts of this option compared to other contingency projects under consideration. It is assumed, however, that YEC will treat this option in the same way as other capacity options noted above, and assess its costs relative to the next best alternatives (keeping in mind as well YEC's ability to sell these relatively mobile units to others at such time as they may no longer be needed by the utility).

2.7 OTHER POTENTIAL NEAR TERM PROJECTS

The section addresses other potential near term resource options which have been reviewed in the Plan or the current proceeding, but are not proposed by Yukon Energy as major near term commitments before the year 2009 involving costs of \$3 million or more. Longer-term options (e.g., DSM, wind, and downstream icing studies at Whitehorse) are addressed in part B below, reflecting the evidence that such options do not offer material near term opportunities. The following options are reviewed below:

[39] Transcript page 238, line 11 to page 239, line 2.

- Marsh Lake Fall/Winter Storage
- Aishihik 2nd Transmission Line
- Whitehorse Diesel Plant Expansion
- Aishihik Rewinds
- YECL Projects

2.7.1 Marsh Lake Fall / Winter Storage

Yukon Energy initially filed for Board review evidence related to Marsh Lake in the Plan (Exhibit B-1) on pages 4-20 to 4-22. It included a description of the opportunity to enhance the output of Whitehorse Rapids Hydro GS by up to 1.6 MW and 7.7 GW.h/yr long-term average hydro energy. This project was initially proposed to provide added capacity by fall 2007, to allow extra capacity to be added in the very near term to aid in meeting shortfalls in that year. It was clearly indicated that this was a much different project than the older "Marsh Lake Top Storage Project" as studied in 1992 which required material incremental flooding. The new proposed Marsh Fall/Winter Storage would cause no flooding above natural high water levels.

Material IRs on this project included the following:

- YUB-YEC-1-10 which address the economic analysis reflecting a combination of capacity benefit (1.6 MW) and energy benefits (up to 7.7 GW.h/yr long-term average hydro energy);
- YUB-YEC-2-18 which discuss the environmental costs to date; and
- UCG-YEC-2-38 which indicated that Yukon Energy was reassessing the ability to proceed at this time.

In the update (Exhibit B-16) Yukon Energy indicated that it had decided not to proceed with the Marsh Lake Fall/Winter Storage project. The meetings with Marsh Lake residents and initial environmental scans indicated a clear inability to have the project licenced in the very near term, as initially planned, due to specific detailed concerns. As cited in the update:

> "Among the concerns noted were specific issues related to shoreline erosion, high fall water level impacts in low-lying areas, and related impacts on the built environment. Although there has been no detailed assessment of these issues, they are not items that can be addressed in a short period of time." (page 2)

In summary, Marsh Lake Fall/Winter Storage can no longer be pursued quickly as a near-term resource option, and therefore one of its most appealing characteristics as described in the initial Plan is no longer available. Nevertheless, Yukon Energy is continuing to assess various options to enhance the Whitehorse Rapids output as described in the Resource Plan. The work at this point is focused primarily on longer-term river ice studies (as discussed below in part B of this argument), as well as a review of other upstream storage options.

During the hearing the Marsh Lake project was brought up in cross examination by YCS, UCG, and the Board Counsel,[40] and questions focused on review of Yukon Energy's reasons for deciding not to pursue this project. Yukon Energy indicated that a lot of opposition from residents had been observed, and noted also the risks and time expected to be associated with amending the Whitehorse water license.[41] These factors combined have lead Yukon Energy to conclude that this project would take up a lot of near term company resources and would be more difficult, expensive and risky than originally anticipated.

No party has called evidence to oppose the withdrawing of the Marsh Lake Fall/Winter Storage Project. To ensure the ability to best use peaking ability of the Whitehorse hydro facility, Yukon Energy proposes to continue to study potential up stream storage options as well as downstream icing effects of different possible peak operating regimes.

2.7.2 Aishihik 2nd Transmission Line

The Aishihik 2nd transmission line was considered seriously during the preparation of the Plan (Exhibit B-1 page 4-34 to page 4-37) and discussed extensively in the hearing. In the end, however, it was not proposed as a near term project (other than as a contingency option in the event that mine loads materialized without completion of the Carmacks-Stewart transmission Project (Stage 2) concurrent with a finding that the Mirrlees Life Extension is not technically feasible - Exhibit B-2, page 31).

The most recent evaluation of the project is addressed in YUB-YEC-2-11 (d) and report provided in YUB-YEC-2-11 Attachment 1. It discusses the project concept, initial technical consideration, routing options, initial environmental/licencing considerations as well as initial costing considerations, which are between $16 and $19 million ($2005).

As discussed in YUB-YEC-2-22, the twinning of the line will provide firm capacity benefits but no new energy benefits. As a result, the project has been compared against other capacity projects as clearly set out in Exhibit B-24 (transcript page 516, line 24 to page 524, line 7), and is not seen as an option to the Carmacks-Stewart Transmission Project[42].

The Aishihik 2nd transmission line not expected to be the lowest cost option for securing the needed capacity as compared with the Mirrlees Life Extension or new Whitehorse diesel capacity.

Under cross-examination from Board counsel, other drawbacks of this project were discussed including the unknown time required to licence and build the transmission line and the lumpiness of it coming on

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[40] YCS cross examination (transcript page 80, line 18 to page 82, line 9); UCG cross examination (transcript page 228, line 2 to page 233, line 22); and Board Counsel cross examination (transcript page 492, line 12 to page 498, line 24).

[41] "So when we looked at the mitigative measures, we also looked at the risk around accepting responsibility for mitigation…. when we looked back at our experience of relicensing Aishihik and thought about the costs, and having to deal with the Water Board, only, back then, we did not have to deal with this YESAB process that is now in place, yes, we may not have had to spend millions of dollars on physical plant, but we felt we would end up spending millions and millions of dollars, an unknown quantity on regulatory process. In addition to that, we felt that timing would take us well out of the time when we really wanted Marsh Lake as a preferred project." (Morrison, transcript page 495, line 19 to page 496, line 12)

[42] Transcript page 396, line 22 to page 397, line 16.

line.[43] The amount of capacity that would be gained from the completion of this project is enhanced significantly if the Aishihik 3rd turbine project is in service.[44]
No party had called evidence to oppose Yukon Energy's recommendation not to pursue Aishihik 2nd transmission line at this time. The only presentation made to the Board in this proceeding, by Mr. John Maissan, supported Yukon Energy's decision (transcript page 411, line 18 to page 412, line 21)

In summary, although Yukon Energy believes that the Aishihik 2nd transmission line is a good project that would provide substantial capacity to the system (and therefore has not been completing ruled out as a future project), it is not currently cost completive when compared with Mirrlees Life Extension Project.[45]

2.7.3 Whitehorse Diesel Replacement/Expansion Project

Yukon Energy initially filed with the Board information on the Whitehorse Diesel Replacement/Expansion project in the Plan (Exhibit B-1) on page 4-32 to 4-33, as an option considered in the Plan.

In YUB-YEC-2-10 (f) on page 4 of 5 Yukon Energy indicates that expansion to the Whitehorse plant is one of their contingency options.

> "In the event that sufficient capacity cannot be secured from the major projects in the Resource Plan, or the above two alternatives [Faro Mirrlees and Minto Diesel Plant], further expansion at the Whitehorse Diesel plant as noted in the Resource Plan is the next identified contingency option."

In the cross examination by the City of Whitehorse (transcript page 289, line 3 to page 293, line 15) the main concern mentioned was the operation of the diesel plant in the city core and the possibility of moving this plant. As indicated by Mr. Morrison "We have no indication of looking at moving that plant." (transcript page 292, lines 22 to 23).

Yukon Energy proposes that in the event that extra capacity is required to meet the N-1 and LOLE criteria on the WAF system that cannot be fully met by committed projects (Mirrlees Life Extension, Aishihik 3rd Turbine and Carmacks-Stewart), adding new diesel units to the Whitehorse plant as reviewed in the above evidence be considered as a reasonable contingency for assessment against other identified contingency projects (including the Minto diesel units and the Aishihik 2nd Transmission Line).

2.7.4 Aishihik Rewinds

As discussed in YUB-YEC-2-9, Aishihik hydro units AH1 and AH2 have both been rewound and have a theoretical combined total capacity of 30.8 MW. The potential electrical capacities of the two units are different as a result of the rewinds as noted in the hearing (transcript page 524, line 7 to page 527, line

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[43] "Two things affected its ultimate ranking at this moment in time. One was the fact that it takes time to licence and plan and build it, and there is a fair amount of uncertainty at the moment with respect to the time period required....The second problem is that it is lumpy. You get it all, and it cost 16 to 19 million dollars." (Osler, transcript page 395, line 14 to page 396, line 3)
[44] "The opportunity on this project to do the second transmission line, though, the benefits of doing the project, are materially enhanced to the extent that a third turbine is in service as opposed to not in service." (Bowman, transcript page 489, lines 14 to 18)
[45] Transcript page 399, line 17 to page 400, line 4.

7). However, until such time as the units are mechanically re-commissioned YEC can not be sure of the capacity increase above the current 15.4 MW. There may be 1 or 2 MW of added capacity available.[46]

No party has called evidence to oppose Yukon Energy's plan for Aishihik Rewinds. In short, the evidence before the Board in this proceeding provides justification for Yukon Energy to attempt to gain and addition 1 or 2 MW of capacity out of AH2 when it is due to be mechanically recommissioned.

2.7.5 YECL Projects

Yukon Energy's Resource Plan includes consideration of all bulk power supply projects in Yukon that are in place or plan to be constructed during the duration of the planning horizon. In particular Yukon Energy notes in YUB-YEC-1-4 that it is not aware of "any YECL production expansion projects or new capacity projects planned."

During cross examination by Mr. Tuck he was concerned about YECL generation in relation to the McIntyre Creek Project. He was under the impression it was a 6.4 MW project. In the transcript page 294, lines 21 to 23, Mr. Morrison clarified that "the McIntyre Creek project is not 6.4 megawatts, it's .64 megawatts. It is a very small project." Yukon Energy has subsequently confirmed, from the 1992 Resource Plan submission, that this project's dependable capacity was approximately 0.6 MW. In addition, Yukon Energy is under the impression that YECL is not planning any generation or transmission as discussed in cross examination by UCG.[47]

3.0 PART B: PLANNING ACTIVITIES TO MEET LONGER-TERM INDUSTRIAL OPPORTUNITIES

3.1 OVERVIEW OF PROPOSED PLANNING ACTIVITIES

Chapter 5 of the Plan (Exhibit B-1) considers planning activities that Yukon Energy may be required to carry out in order to start construction on generation and transmission projects before 2016. The Plan notes that these activities would be required primarily to meet the needs of potential major industrial customers. In the past industrial developments have proven to support development of long-term cost effective electrical infrastructure in Northern Canada (Exhibit B-2, page 8). Accordingly Yukon Energy proposes to balance costs associated with resource project planning and readiness and timing to supply potential new industrial loads.

Yukon Energy discusses four potential Industrial Development Scenarios on pages 5-7 to 5-27 of the Plan (Exhibit B-1). They include a 10 MW, a 25 MW, and a 40 MW WAF Industrial Scenario as well as a 120 to

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[46] "...for the second unit, the works was awarded to a different vendor who, in fact, was able to guarantee a higher rating, electrically of the unit. And we feel while, electrically, potentially there is 1 or 2 more megawatts available electrically, right now on that unit, if we are able to achieve it mechanically, then we will at that point be able to recommission Unit 2 as high as 17 to 17 and a half megawatts." (Campbell, transcript page 526, lines 4 to 2)

[47] "YECL had made a similar comment to me, Well, are you taking into account other generation or transmission plans that Yukon Electric might have? And my response to them was, Well are you planning to build any? And the response was no." (transcript page 153, lines 22 to 26)

360 MW WAF Alaska Highway Natural Gas Pipeline Scenario. To meet the needs of these potential loads many supply options are considered. These include hydro, coal, natural gas, wind, DSM, and IPPs. Further information on some of the supply options considered is located in Appendix A of the Resource Plan (Exhibit B-1) and the Backgrounder in the Overview (Exhibit B-2, pages 50 and 51). Many of these long term options focus on fossil fuel reduction as outlined in UCG-YEC-2-25.

To ensure that the required information is available in the event that additional hydro capacity can be added to the grid, Yukon Energy has stream gauging stations on Drury Creek and Morley River. As indicated in YUB-YEC-2-20 this hydrological information would be one of the factors used to rank potential hydro sites.

During the hearing (as well as in the IRs) only limited attention focused on these longer-term elements of the Plan and the Minister's direction for the current review.

3.2 REVIEW OF ISSUES RAISED BY PARTICIPANTS

The following resource project-specific issues raised by participants were discussed as part of Yukon Energy's long term plans.

3.2.1 Whitehorse Hydro Peak Capacity - Downstream Icing Studies

In the 1993 to 1995 period, pursuant to directives of the YUB, Yukon Energy hired Acres to conduct a study (YUB-YEC-2-15 Attachment 1) on the potential for increased winter capacity from the Whitehorse plant and constraints on this capacity related to icing.[48] At that time, the risks related to ice and the potential to flood Whitehorse were judged to exceed the potential benefits from changing the way Yukon Energy operated the plant.

The potential winter capacity benefits of this option were not reconsidered again until recently because until the start of the Plan (Exhibit B-1), and changing the capacity criteria, there was not a capacity shortfall.[49] In addition, the capacity potential indicated in the Acres study is relatively small when compared with other projects and could potentially result in downstream flooding.[50]

In the hearing under cross examination by Board Counsel, Yukon Energy confirmed the amount of potential capacity increase was relatively small. Yukon Energy also indicated that a sudden release of water in an emergency is more likely to over-top the ice front and cause over-ice flooding.[51]

Yukon Energy reviewed during the hearing the history of downstream icing studies, the recent commissioning of a further study into the icing conditions, and its assessment that it will take several years to study and assess any practical implementation options.[52]

[48] "There were some additional icing studies done, I think the Acres studies went on to about 1995, but the results were not implemented because there was little benefit and considerable risk." (Campbell, transcript page 325, line 24 to page 326 line 1)
[49] "So when we started off, there was not a capacity shortfall in front of us..." (Osler, transcript page 331, lines 11 to 12)
[50] "It is a very difficult option to pursue, it has not got a big pay-of." (Osler, transcript page 332, lines 21 to 22)
[51] "A sudden release of water is more likely to over-top the ice front, and you would have over-ice flooding..." (transcript page 336, lines 23 to 25).
[52] Transcript page 325, line 13 to page 334, line 26.

To better understand the icing issues and the potential winter capacity of the Whitehorse plant, Yukon Energy is committed to studying this opportunity further and assessing any practical options that may emerge to enhance firm winter peaking capability at the Whitehorse Rapids Hydro plant in a way that does not pose added risks of flooding in Whitehorse.

3.2.2 DSM

Yukon Energy reviewed DSM activities in preparing the Resource Plan, and provided summaries of the DSM activities that have been carried out in Yukon in Chapter 2 of the Resource Plan. However, at the present time, the supply requirements of the integrated systems, particularly WAF, are focused entirely on capacity, which is not well suited to DSM, as reviewed at YCS-YEC-2-A2.

Yukon Energy was involved in Demand Side Management ("DSM") while the Faro mine was still operating as discussed in the Plan (Exhibit B-1) page 2-19, line 22 to page 2-22, line 18. Since the 1993/94 GRA, when the Faro mine was closed, DSM was limited in the Board's Decision 1993-8 to spend money solely on public information. This is discussed in more detail in YUB-YEC-2-19. The goal was to minimize the rate impact from the closure of the Faro mine.

As indicated in UCG-YEC-2-31 Yukon Energy has researched other jurisdictions including Newfoundland and Manitoba while preparing the current Plan. However due to the surplus energy on the system Yukon Energy does not propose to pursue DSM at this time unless load growth including industrial loads (Minto and Carmacks Copper) arise to bring baseload diesel onto the WAF system (see Attachment C page 5). The current state of surplus hydro energy has lead Yukon Energy to develop DSM to expand use of this resource (i.e., the Secondary Sales program to give commercial customers who maintain other forms of heating the opportunity to buy interruptible power at reduced rates, as discussed in YCS-YEC-2-A2). This specific DSM measure helps Yukon Energy keep rates down for all customers.

DSM was discussed during the hearing by YCS, UCG, and the City of Whitehorse.[53] There were questions about DSM and Minto mine. Mr. Osler made it clear that "… they are going to be paying through the nose for diesel fuel. They have every incentive in the world to be efficient in their use of energy." (transcript page 85, lines 18 to 21) Once Minto mine joins the grid no specific DSM activities are currently planned with this customer due in part to the short duration of the mine life.[54]

As noted in the Plan, Yukon Energy will pursue investment in DSM programs on WAF to reduce energy and capacity loads when base load diesel generation is once again required on a sustained basis.

[53] YCS cross examination (transcript page 84, line 25 to page 87, line 19); UCG cross examination (transcript page 124, line 20 to page 127, line 23); and City of Whitehorse cross examination (transcript page 302, line 18 to page 308, line 2). Mr. Maissan also addressed DSM opportunities (transcript page 415, line 21 to page 418, line 15).

[54] "The likelihood for a mine of this length of life getting into big investment of DSM, of the type we are talking about, I am not aware of a lot of options that they would get into. As I said earlier, it is not quote the same as dealing with, say, the Inco mine in Manitoba that has been there for a long time and expects to be around for a longer time." (Osler, transcript page 126, line 7 to line 10)

3.2.3 Wind

As indicated in UCG-YEC-2-8 (a) Yukon Energy is not currently actively pursuing the development of new wind farm sites. However, Yukon Energy would consider sites on a case by case basis if they are located near existing transmission lines and the power systems have diesel on the margin. As discussed in the hearing under cross-exam by Mr. Tuck (transcript page 309, line 14 to page 312, line 12) wind provides no firm winter peak capacity benefits. Currently the two Haeckel Hill turbines operate only about 15 percent of the time and cost about 31 and a half cents a kilowatt hour.

Wind energy is currently an expensive alternative that provides no capacity, only energy benefits. As noted in the Plan and in particular Appendix A of Exhibit B-1, when Yukon Energy is required to start running diesel on the margin it is prepared to consider wind generation as an option to displace diesel generation along with other possible energy resource options available to meet this same objective.

4.0 PART C: OTHER ISSUES BROUGHT FORWARD BY INTERVENORS

4.1 PLANNING FRAMEWORK INCLUDING CONSULTATION WITH STAKEHOLDERS

Yukon Energy has consulted with stakeholders during the preparation of the plan "aimed at receiving information about potential loads an supply options" (UCG-YEC-2-24) and to ensure that the information presented was accurate.[55] In addition since the completion of the 20-Year Resource Plan Yukon Energy has sought review from the Board, the public, and other stakeholders as discussed below.

4.1.1 YECL

In YUB-YEC-1-18 and UCG-YEC-2-45 Yukon Energy describes the discussion it had with YECL during the preparation of the Resource Plan. Yukon Energy attempted to discuss loads, plans and data requirement with YECL. As indicated in YUC-YEC-2-45 "Although Yukon Energy was not successful in securing data from YECL… the proposals in the Resource Plan are not materially affected by the potential range of variability this data might clarify" (page 1, lines 34 to 36). As such Yukon Energy is confident with the forecasts that it presented. More detailed retail customer information would be needed in future, however, for YEC to consider new DSM initiatives including measure to curtail use of electric heating.

4.1.2 Others Stakeholders

Consultation was done with other stakeholders including various mining companies, potential power producers, and power purchasers as described in UCG-YEC-2-24 to get accurate information to use in the Plan. After the completion of the Plan, extensive public consultation was done including publishing the entire Resource Plan and Overview document, making information available on YEC's web site, providing press briefings and media releases and conducting public meetings. For an inclusive list of activities undertaken by Yukon Energy please refer to YUB-YEC-1-17 and Attachment A to Exhibit B-8.

[55] "The potential industrial customers that the Plan was trying to address, so we wanted to make sure that we had as good information as we would for the purpose of doing the Plan." (Osler, transcript page 145, lines 14 to 17)

4.1.3 British Columbia Utilities Commission Resource Planning Guidelines

In the hearing under cross-exam from UCG regarding the British Columbia Utilities Commission Resource Planning Guidelines (BCUC) (transcript page 132, line 24 to page 148, line 20) it was noted that although BCUC requires a significant amount of stakeholder input before bringing a resource plan to the BCUC, in the Yukon the situation is very different. In Yukon, there is not the same large number of players, IPPs or industrial customers as in British Columbia or other places.[56] Nevertheless, as indicated above, other stakeholders were consulted during the preparation of the Plan to ensure that accurate information was being used. In the preparation of this Plan, Yukon Energy chose to create a document for others to review so that the overall process could be done in a timely manner and give people a starting point from which to discuss the issues and options.[57]

4.1.4 Commitment to Consult

Yukon Energy is prepared to consult with Stakeholders prior to doing an updated resource plan as indicated during the hearing. Yukon Energy strongly feels this process would have been very difficult and time consuming without a baseline document, which it now has.[58]

4.2 GOVERNMENT ENERGY POLICY

In the hearing the future government energy policy was a concern brought forward by UCG (transcript page 161, line 16 to page 164, line 23). They wanted to know if Yukon Energy had considered the implications that a future government energy policy would have on the Resource Plan. Mr. Morrison indicated that if and when the Yukon government produces an energy policy Yukon Energy will update its Plan accordingly.[59]

4.3 PROJECT MANAGEMENT SKILLS

During the hearing UCG introduced the Auditor General's Mayo-Dawson City Transmission System Project Report (Exhibit C3-13). The main relevance of this discussion pertained to Yukon Energy's project management skill at handling a large project such as Carmacks-Stewart. This is reviewed earlier (section 2.5.3). In addition to providing copies of YEC contracting polices, Mr. Morrison insisted that "…prior to going ahead with the final decision, we will get a tendered price, and if we don't think the cost is still within the economic range, we won't proceed" (transcript page 204, lines 20 to 23).

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[56] "Unfortunately, or fortunately as the case may be, in Yukon, there is not the same institutional large number of players, IPPs, industrial customers, and everybody else that there would be in British Columbia or Manitoba or other places…" (Osler, transcript page142, line 22 to page 143, line 1)

[57] "We chose to do it in a manner that would say we have prepared a Plan; what do you think of the plan? So rather than give people nothing as a starting point, and not having the benefit of all this information, it was our clear understanding that what we wanted to do was provide a comprehensive Resource Plan that interested persons and regulatory authorities, inducing the YUB and YESSA. Could look at, and then we could take that input from that point onward." (Morrison, transcript page 146 lines 3 to 13)

[58] " …I prefer having something to discuss and review, as to starting, you know, with everybody providing input and not really knowing where the direction is. So I think, now that we have got that, we would certainly talk to stakeholders prior to doing an update. But we have a document to update now. We have something that we can actually discuss with stakeholders, and I think that would be appropriate."(Morrison, transcript page 148, lines 8 to 16)

[59] "I do not know when the government will address energy policy, and I don't know how long it will take them to address energy policy. So I think in the interest of management of the utility and the assets and the interests of the ratepayers, it Is important we proceed." (Morrison, transcript page 164, lines 19 to 23)

UCG wanted to know if Yukon Energy had completed a "Project Management Policy" as discussed in Exhibit C3-13; Mr. Morrison noted that the actual commitment referenced was to undertake an audit of project management policies. Although Yukon Energy to date has not had the resources to carry out this undertaking, Mr. Morrison stated that it is still a commitment to the Board of Directors.[60]

Yukon Energy is confident that it has the project management skills and contracting policies required to execute the near term projects.

4.4 ENVIRONMENTAL ISSUES

During Cross examination, Ms. Marx enquired about environment issues indicated in the NTPC report relating to the Mirrlees leaking oil and fuel. (transcript page 470, line 8 to page 475, line 14). Mr. Morrison indicated, after review of an earlier NCPC oil spill prior to the creation of YEC, that "We have no environmental issues, no oil spills around the plant, no fuel spills, in recent years…" (transcript page 471, lines 11 to 12). A geotechnical assessment was recently done due to the NCPC fuel spill that occurred before the Yukon Government acquired the utility.[61] He stressed that the Mirrlees units do not leak outside the plant but into a bucket (transcript page 740 lines 23 to 23).

Mr. Campbell added the following statement.

> "Yukon Energy does have a very comprehensive environmental management system, and part of that system, for example, requires environmental audits be conducted every five years, and we have certainly been doing that on all of our facilities" (transcript page 474, lines 21 to 26)

Mr. Tuck, during cross examination (transcript page 287, line 23 to page 289, line 2) expressed concerns related to greenhouse gas emissions and noise pollution from the operating for diesel engines. Mr. Morrison indicated that Yukon Energy follows all the regulatory guidelines in terms of environmental standards. In addition Yukon Energy has permits to operate the diesel pant which are renewed on a regular basis.[62]

No party has called evidence in this proceeding to oppose any aspect of Yukon Energy's Environmental Practices.

4.5 IPP POLICY

Yukon Energy outlines its current position on IPPs in the Plan (Exhibit B-1) in section 5.3.1.4 (pages 5-36 to 5-38).

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[60] "We have not had the resources, nor have we been able to find the time to complete the audit. It is still on our books, it is a commitment we have to our Board of Directors, and we will continue to make that commitment and complete this but, at this moment, we have not been able to do it." (Morrison transcript page 207, line 22 to page 206, line 2)

[61] "… I think what we have gone through gives s quite a bit of assurance, quite a bit of comfort, that there are not any others out there; we have gone thorough a pretty extensive program." (transcript page 474, lines 9 to 12)

[62] "We are required, as everyone else is, to follow the regulatory guidelines in terms of environmental standards. We have permits for the operation of our diesel plant. Those permits are renewed on a regular basis." (Morrison, transcript page 288, lines 15 to 19)

As indicated in YEC-YCS-2-C1, Yukon Energy does not currently have an IPP policy in place. Up until recently there has been surplus capacity and energy on the system and thus there was no need for new projects.[63] However as the system grows Yukon Energy is prepared to look into developing an IPP policy.[64]

ALL OF WHICH IS RESPECTFULLY SUBMITTED

P. John Landry
Counsel for Yukon Energy Corporation

November 24, 2006

[63] "When we look at IPPs - - and we talked yesterday about, you know, and IPP policy, and the fact that we don't have one, but at the moment, Madam Chair, we have a surplus of hydro on the grid. So it would not be our intent to put forward any call for people to submit proposals to us to supply power because we don't need to buy any power at the moment." (Morrison, transcript pages 296, line 23 to page 297, line 4)

[64] "I think it is fair to say that we will move towards the development of an IPP policy within the next few years." (transcript page 91, line 22 to line 24)

ATTACHMENT A

ATTACHMENT A: YUKON ENERGY'S CAPACITY PLANNING CRITERIA

1.0 OUTLINE OF THE FILED EVIDENCE

Yukon Energy has filed with the Board the new capacity planning criteria that it has adopted, and a comparison between the new capacity planning criteria to the previous criteria including reasons why the previous criteria is no longer appropriate. In particular, this includes the following key information:

- **Resource Plan January filing (Exhibit B-1) (Pages 3-11 to 3-26):**
  - Summary of previous WAF capacity planning criteria; indicates there was no previous MD criteria.
  - Description of inadequacies related to applying previous WAF criteria to today's system.
  - Summary of new capacity planning criteria adopted by Yukon Energy.
- **Key First Round IRs (Exhibit B-6):**
  - YUB-1-1: Copy of Dr. Billinton's report and scope of work.
  - YUB-1-2: YEC criteria similar to NWT, and well-founded practice in industry.
  - YUB-1-6: Justification for new criteria, particularly N-1 criteria focused on Aishihik transmission line.
  - YUB-1-12: LOLE approach adopted (hours/year) more suitable for Yukon than alternatives like energy-based measure (MWh/yr, or EENS).
- **Key Second Round IRs (Exhibit B-12):**
  - YUB-2-2: Support for 2 hour/year LOLE criteria.
  - YUB-2-3: YEC beginning to collect its own data, but for now uses industry-wide Canadian Electricity Association averages to determine probabilities of outages for the Aishihik transmission line.
  - YUB-2-7: Details on NWT PUB-approved criteria (which largely parallels YEC's adopted criteria) including copy of the relevant NWT Public Utilities Board Decision.
- **Relevant transcript sections:**
  - Pages 41-51: Presentation: Capacity criteria adopted by YEC.
  - Pages 74-79: Direct examination of Dr. Billinton: Confirming reasonableness of YEC's adopted criteria, and how it is generally consistent with criteria used in many other jurisdictions in Canada.
  - Pages 197-200: Cross-examination: New criteria are more responsive to factors that influence the reliability of the system, compared to previous criteria.
  - Page 339-347: Cross-examination: Energy based probabilistic criteria (LOEE, EENS, system minutes, units per million, etc.) are harder to understand and although can be useful tools in some cases, are less preferable than an LOLE approach in Yukon.
  - Page 369-370: Cross-examination: N-1 criteria are standard in NERC, and are based off the single highest peak.
  - Page 446-450: Cross-examination: Use of all loads to calculate LOLE criteria, and only non-industrial loads to calculate N-1 criteria

- Page 537-541: Redirect: Practical implications of not having the N-1 criteria in the event of a loss of Aishihik transmission line in winter.
- Page 541-544: Redirect: Must plan system to meet peak, even if it occurs only a relatively small part of the year.

2.0 SUMMARY OF THE EVIDENCE

As noted at transcript page 43 lines 15-17, "any utility has to have a means to determine when it has sufficient capacity installed and to know how much to install". This requirement results in the need for bulk power utilities to have in place a capacity planning criteria. As reviewed at section 3.3 of Exhibit B-1, prior to this proceeding Yukon Energy adopted a new capacity planning criteria.

2.1 PREVIOUS CRITERIA INADEQUATE

The evidence in this proceeding indicates the previous capacity planning criteria Yukon Energy had in place prior to 2005 is now inadequate. Yukon Energy began to recognize a concern in this area prior to the 2005 Required Revenues and Related Matters hearing (transcript page 45 line 24 – page 46 line 19). As noted by Mr. Morrison, Yukon Energy hired one of the world's top experts in the field in Dr. Billinton (transcript page 21 lines 3-17) and had a detailed review performed of the reliability of the WAF system in particular (Dr. Billinton's reports are filed at Attachments 1 and 2 to YUB-YEC-1-1, Exhibit B-6).

A general summary of the results of Dr. Billinton's findings, as applied to the WAF system, are provided at page 19 of Exhibit B-2. Those findings reflect Dr. Billinton's calculations of the Loss of Load Expectation ("LOLE", measured in average hours per year that the system generation and in some cases transmission will be inadequate to supply the loads). In particular, this summary notes:

> "Dr. Billinton's work indicated that YEC's capacity criteria as reviewed in the 1992 Resource Plan assured a highly adequate amount of generation (based on LOLE) for residential and commercial WAF customers when the Faro mine was last operating (1996/97). Today, however, Dr. Billinton's work indicated that the 1992 criteria would allow maximum peak loads to reach a level well beyond the reasonable capability of the system before the criteria would indicate new generation was required.
>
> The primary reasons for this conclusion are that the WAF system has substantial hydro generation at Aishihik contingent on the Aishihik transmission line being available. The 1992 criteria did not consider the risks inherent in this transmission connection. In addition, in 1996/97, the system had Faro mine loads that could be interrupted in an emergency as a first resort if the loads began to exceed available generation. Today, there are no similar mine loads to be interrupted, and a similar shortfall condition today would have to be met with outages to core residential and commercial customers." (Exhibit B-2, page 19).

2.2 NEW CRITERIA APPROPRIATE AND CONSISTENT WITH OTHER JURISDICTIONS

The new capacity planning criteria adopted by YEC are set out in Exhibit B-2, page 20. They comprise:

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

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

WAF and MD "community" guidelines (note this previously was incorrectly called a "criteria" – transcript page 50 line 24 – page 51 line 15): For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

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

At the most general level, the Board heard evidence from Dr. Billinton that overall, the new Yukon Energy criteria are reasonable. In particular, Dr. Billinton provided the following testimony at transcript page 74 line 23 - page 75 line 9:

> "Q: Now, sir, in your view, given your experience, is that criteria reasonable for the Yukon systems, particularly in light of similar planning criteria used elsewhere in Canada?
>
> A: Yes, I think it is quite reasonable. It is understandable and straightforward. It lies, I think, in the range of planning criteria that are used elsewhere in Canada. And it, of course, relates directly to the criteria that are being adopted in the Northwest Territories for a very similar system. So, therefore, I think it provides a very practical and reasonable framework upon which to conduct adequacy evaluation.

Dr. Billinton went on to testify under cross-examination that the criteria are well accepted by other jurisdictions and regulatory authorities, including in the transcript and other evidence as follows:

LOLE criteria

- **Page 349 line 26 – page 350 line 10:** LOLE approach in use in NWT for a system with very similar topology and underlying factors influencing reliability as the WAF system.
- **Page 340 line 23 – page 344 line 7, as well as YUB-1-1 Attachment 1 page 7:** LOLE used by BC, Alberta prior to deregulation, Manitoba, Quebec, Nova Scotia and Newfoundland and Labrador.
- **Page 345 lines 1-26:** LOLE also used by very large systems, such as the Pennsylvania-New Jersey-Maryland system.

N-1 criteria

- **Page 356 line 26 – page 357 line 13:** N-1 approach is embedded in NERC (North American Electric Reliability Council) standards that apply throughout North America.

The evidence provided also reviews the criteria adopted in NWT, including YUB-YEC-2-7 of Exhibit B-12, which includes the full NWT Application and PUB decision. As noted in those materials, the criteria in place in NWT are basically identical to that adopted by YEC, with the exception that in the case of the NWT N-1 criteria, the system must meet the peak load plus 5% for load forecast uncertainty (also see transcript page 543 line 14 to page 544 line 1).

2.3 NEW CRITERIA BALANCES DIFFERENCES BETWEEN INDUSTRIAL AND NON-INDUSTRIAL LOADS

The largest practical difference between the LOLE criteria and the N-1 criteria is the calculation, or base of loads, to which the criteria will apply. The LOLE criteria is designed to ensure all firm loads (including industrial customers being served at firm rates) receive reasonable utility-grade supply from the system as follows at transcript page 446 line 7 - page 448 line 9:

> "Q: Mr. Bowman, yesterday when we were talking, I was left with the impression that you have factored in the mine loads in your calculation of the LOLE. Is that correct?
>
> A: Yes, when you are looking at the LOLE calculation, and the analysis of the entire system, you would look at all loads on the system, which includes the mine loads, and that is consistent with the way Dr. Billinton dealt with the system in his second report filed in response to YUB Question 1, the first round interrogatories, where Yukon Energy asked him to take what had he done in his first report, looking to the system today, and apply it to the system as it existed when the Faro mine was on, and he showed the impacts with the Faro mine associated with the LOLE calculation. And, as a result of that, and further discussion, what has been adopted by Yukon Energy is a criteria that says the LOLE will apply to all loads on the system, whereas the N-1 would apply to all those loads who do not have their own back-up, their own ability to supply their own power in emergency situation, which, for the purposes of calculation, means all loads, less the mines.

Q: You know, I thought the same would have applied to the LOLE, that, since the mine loads are interruptible, that you would not factor that in to the LOLE either.

A: Well, let me be really clear. The mines are not contemplated to be provided with interruptible power, in the sense that we talk about interruptible rates in other jurisdictions, or secondary power here, or something of that nature.

Q: Fair enough.

A: The service to the mines is intended to be a firm service that Yukon Energy would provide. It would provide in all hours of the year, as able to provide it, whether from hydro or from diesel, to a utility standard, including to a standard that would mean a LOLE of two hours per year. The comment about interrupting the mines goes more to when you have turned your mind over from design of the system, to what does one have to do when we hit those emergency situations. And when we hit the emergency situations, and you know the mines have their back-up, and they can keep themselves from freezing, Yukon Energy would turn its attention to keeping other people from freezing in the dark, as opposed to the mines, who can do that for themselves. But it doesn't go into the criteria type of analysis which says, in providing service to the mines, the system will be able to provide them with utility grade firm service meeting an LOLE of two hours per year, or better."

Nonetheless, despite the presence of the LOLE criteria there is a significant additional protection required, given the topology of the Yukon System, to reflect the exposure to the non-industrial customers to the Aishihik transmission line. This is an added measure to reflect that, unlike mines, most customers do not maintain their own backup to supply their necessary loads in these situations, as discussed at page 448 line 10 to page 450 line 24:

"Q: Aren't you designing the system to meet the requirements, not specifically to the mines? Like, you are not designing the system to meet the load requirement of the mines because, as you say, you know, in an emergency situation, you can curtail the power to the mines to try to serve other customers.

A: No, that is not quite correct. The system would be designed -- let me go back a step. The system has always been designed, under the previous criteria, to incorporate the mine loads. The calculation that was done in the past, on the deterministic criteria, always looked at all loads, including the mines. The '96 GRA, for example, if you looked at the peaks and measurement of the criteria, always had the Faro mine in at about 25 megawatts, at that time, in terms of determining the adequacy of the system. So it has always been a component of planning the system. The LOLE criteria continues that approach, that the system will be planned to ensure reliable service to all customers, including the mines.

The only variation today is that Yukon Energy is proposing to add this additional, more stringent at the present time, particularly more stringent with regard to Whitehorse or retail loads, N-1 criteria, that says, even if I have designed my system to provide utility grade power at a long-term average of two hours per year, I want to also be attentive to the impact that can arise from a lengthy outage of the Aishihik line, which is what the N-1 criteria is meant to address. And it goes to ensuring that the -- that, in looking at the LOLE criteria, and the long-run averages, coming up with two hours per year, one has not ignored that there is a situation where you

> would want to be better protected than that, relating to long outages that can arise with the Aishihik line.
>
> And just in case it is not clear in the information that has been filed, the N-1 criteria, which looks to the failure of the Aishihik line, as experienced on January 29th, it is a very important example in terms of emphasizing that this can happen, it does happen, it has happened during winter, it looks to what you will do in that situation. The N-1 criteria does not provide any guarantees; as a matter of fact, you are basically guaranteed the opposite, that if the line, as the system is currently designed, goes out, or you lose Aishihik, you will have an outage. It loses simply too much generation for the system to be able to absorb. So when the Aishihik line goes down, under any of the criteria, and in the absence of a second line, you will have an outage. ***The point is, if that line stays down, what can you do to get the lights back on? And the N-1 criteria is designed to say, if the lines stays down, I am going to have enough megawatts this side of Aishihik to be able to restore power up to my expected peak load.***
>
> ***Without the N-1 criteria, you may have a system that is planned, that does not have enough megawatts this side of the Aishihik line, to keep the lights on in Whitehorse, or in the remainder of the system. And that is what that criteria does. It is about how to deal with it, if an event occurs, and to deal with that type of restoration***." [Emphasis added]

3.0 ISSUES RAISED IN OTHER EVIDENCE

No party has called evidence to oppose any aspect of Yukon Energy's new capacity planning criteria.

The only presentation made to the Board in this proceeding, by Mr. John Maissan, supported the new YEC criteria, at transcript page 411, lines 10-17.

4.0 ISSUES RAISED UNDER CROSS-EXAMINATION

There are four issues noted by YEC arising from cross-examination:

1. The potential use of an energy-based criteria (such as LOEE) instead of the LOLE criteria.
2. The need for two criteria, particularly in light of the N-1 criteria being the dominant criteria during the planning period.
3. Data limitations and the use of Canadian Electricity Association national data.
4. Peak periods only occurring for a short part of the year.

Each of these matters is addressed in the following sections.

4.1 THE POTENTIAL USE OF AN ENERGY-BASED PROBABILISTIC CRITERIA (SUCH AS LOEE) INSTEAD OF THE LOLE CRITERIA

Under cross examination by Board Counsel, Yukon Energy's witnesses and in particular Dr. Billinton addressed the relevance of a probabilistic LOLE criteria in contrast to other potential probabilistic measures, such as an "LOEE" or loss of energy expectation measure.

In his direct testimony, Dr. Billinton indicated the LOLE is the most common approach around the world (transcript page 77 line 4 – page 79 line 2). In particular, as follows:

> "Now, the bulk of the applications that you see around the world, the loss of load expectation is by far the more common. The loss of energy expectation is a good index, it has been used in numerous situations, but the loss of load expectation is by far the most common index. I think it is understandable. It is relatively easy to calculate, and as a result, I think it serves the purposes that you are looking for." (transcript, page 78 lines 14-22)

In cross-examination, Dr. Billinton went on to provide a detailed explanation at page 340 line 4 – page 346 line 8 that set out the approaches used by a number of utilities in Canada, dominated by LOLE but including 2 cases of variants on LOEE (Saskatchewan and the former Ontario Hydro). The testimony sets out two difficulties associated with applying an LOEE index compared to an LOLE as follows:

1. The additional steps required to "normalize" the output to a value that can be compared to other utilities:

   "See, the difficulty with the energy index is that, as your system grows, the amount of expected unserved energy will increase, only because your system is growing. So, therefore, you have to find some way of normalizing that so that you can have an index which can be used over time as your system changes size." (transcript page 342 line 18-24)

   If we go to the next one, Ontario Hydro, you will see that they use expected unserved energy, but they decided that they are going to normalize it in a somewhat different way, so they divided the expected not supplied, whose units are megawatt hours per year, by the system peak. Now, loosely, now, you can divided megawatt hours by megawatts, and you will get hours. If I multiply it by 60, I will get minutes, so I will call that system minutes. So their criterion was 25 system minutes. Again, it is an attempt to normalize it so that they could use it on a continuous basis as their system changed size, and also, hopefully, you might compare it with somebody else, but unfortunately, nobody else does that so, therefore, it makes it very difficult to compare." (transcript page 343 line 15 to page 344 line 5)

2. The increased difficulty understanding the index compared to LOLE:

   "So the loss of load expectation is an index, which, when you see it, I think it is more understandable and observable than system minutes and upm. Those minutes, by the way, system minutes, are not real minutes, they are actually the minutes at the time of system peak which, if the system had an outage, would result in the same

> expected energy loss as the calculated value through a probabilistic analysis. I don't want to belabour this, but if you really want to explain that to somebody, you are going to probably have to do it several times to get your point across.
>
> So it is an index which, from my point of view, is a good index, but which is not the kind of index that you might want to put before a Board, or before the public, or before the government, with respect to understanding. And the loss of load expectation index is a very useful and a very straightforward one." (transcript page 344 line 8 – page 344 line 19).

Finally, Dr. Billinton went on to note that studies he has conducted indicated no practical difference in system planning between use of LOLE and LOEE, so limited additional benefit is achieved by using an LOEE index:

> "Q: Just to follow up a couple of points ... so I can certainly see how the loss of load expectation is easier to explain and communicate to the general public, et cetera. From your strictly engineering point of view, setting aside the ease of understanding by the general public, which do you think is a better indice? Like, which tells you more, which is more helpful, the loss of load expectation, or the LOEE?
>
> A: Well, I think, in a general sense, and we have done studies in the past to look at capacity expansion, and, striking a base value in each particular case, you would finish up pretty much with the same sequence of capacity additions. Because what happens when you do capacity planning, notwithstanding the range of things that have been looked at here, but just, let's say, more conventional capacity planning, the index would provide a trigger for the need to inject some capacity in there for some money into the system, and in either case, I think they would, starting from an equivalent point, they would inject the same signals into the system. So from that particular point of view, there is nothing to choose between them, in that particular case. (transcript page 346 line 12 – page 347 line 10)."

Dr. Billinton completed this line of cross-examination by noting that an LOLE approach can never provide information about the amount of energy that will go unserved – it is the wrong tool for that job (transcript page 348 lines 17-24) as it inherently measures units of hours not MW.h. However, equally true is that an LOEE-based approach can never provide the long-term average number of hours that the system will experience shortfalls related to generation adequacy, as it inherently measures units of MW.h. In YEC's view, it is strongly preferred to be able to understand and communicate reliability measures with the public, regulators and customers using an index measured in simple hours than in "MW.h not served.

As a result YEC agrees with Dr. Billinton that energy-based measures such as LOEE are not as appropriate criteria for Yukon as those adopted by YEC. In particular, the increased complexity YEC sees with the LOEE-based approaches, the more limited ability to readily compare standards with other jurisdictions, and the limited additional value it provides (if any) in terms of determining the optimum system expansion plan all serve to emphasize the appropriateness of the LOLE approach.

4.2 THE NEED FOR TWO CRITERIA

At various points in the interrogatories and cross-examination, including most notably pages 355-358, the issue of the need for the N-1 criteria, given the adoption of an LOLE criteria, is raised. This exchange between Board Counsel and Dr. Billinton sets out a clear rationale for the adoption of an N-1 criteria, as follows:

> "Q: And if you have the probabilistic criteria in place, in your view, just briefly, what is the justification for having a deterministic criteria as well?
>
> A: Well, the justification for the deterministic criteria is with respect to particular incidents, and the severity of those incidents as recognized by the particular system you are dealing with, and the topology of that system. And I presume, of course, you are leading towards why would we want to have a probabilistic index and a deterministic index as a dual criteria in the case of the Corporation. Is that the direction?
>
> Q: Sure.
>
> A: Yes. So when you look at the probabilistic approach, you get the overall assessment, you get the overall assessment of the adequacy of the system, in terms of its ability to meet the total system load, but generating capacity adequacy assessment deals with the ability of the total generating capacity to meet the load requirement, and it is not focused on any one particular portion of the system.
>
> ***Now, when you look at most systems, the generating capacity adequacy does not, in itself, normally incorporate transmission facilities, because the transmission is usually redundant. I don't know of very many systems, perhaps other than next door, in which you finish up with a large amount of your capacity on the end of one transmission line, a single transmission line. Therefore, that system is particularly vulnerable to the outage of that particular facility.*** [Emphasis added] And it becomes obvious, when we started to do our probabilistic assessment, that the indices were very much affected by the transmission line between Aishihik and Whitehorse.
>
> So when you look at that, and you see the vulnerability that is associated with it, and you think of the criteria that are very often used in conventional planning, even in those utilities which use adequacy assessment using probabilistic approaches, and that is the N-1 criterion, which is embedded within the NERC, the North American Electric Reliability Council, criteria with respect to system planning, then you see that ***the N-1 criterion is an important criterion, and particularly important in this particular case, because the loss of that line has immediate and drastic consequences upon the continuity of supply at Whitehorse***. [emphasis added]
>
> So, therefore, there is a need for, I think in that particular case, to recognize that vulnerability, and I think it was driven home, as I said yesterday, very dramatically on January 29th last year, and that was the loss of that line. So the N-1 criterion is immediate, it is a non-probabilistic index. It says the system should be able to withstand the loss of any single element, whether that element is a generator, a transmission line or a transformer. In fact, those are the conditions that are outlined

> in the NERC standard under Condition B, the three conditions that should be satisfied.
>
> So there is precedence again for that. And I think, in this particular case, because of the topology of the system, because of the topology of the system, then it has an immediate and a drastic effect with respect to the adequacy at the Whitehorse bus, which is the largest component, the largest load component, in this particular system."

Dr. Billinton went on to confirm at pages 359 line 26 to page 360 line 25 that he played an integral role in YEC's decision to adopt the N-1 criteria in conjunction with the LOLE criteria:

> "Q: Am I correct to say that you did not recommend, on your own, the N-1 criteria, but, to put it simply, perhaps you did not see a big problem with YEC adopting that, or you thought that was acceptable?
>
> A: I do not think it was -- I would like to think it was nice and clear-cut as that. But what we had was a really good workshop here, in July I guess, of last year. We came with our report, we made our presentation with our report, with respect to benchmarking the loss of load expectation index. We then discussed the Northwest Territories situation, we discussed the similarity and impact of a line failure on Yellowknife and a line failure upon Whitehorse, and I guess, through discussion, we gravitated to the fact that the existing deterministic criteria could not be modified and extended to meet the requirements. A probabilistic requirement was required, but, because of the vulnerability of Whitehorse, that the N-1 criterion was a good criterion that should be added to form a dual situation.
>
> I do not think -- I think you would be quite wrong to say that I suggested it, or I went along with it. We just had a really good discussion, and I think sort of arrived at that particular position on a collective basis."

Later in that exchange at transcript page 370 line 22 – page 371 line 18, Dr. Billinton confirmed the valuable role an N-1 criteria plays in the two-part approach adopted by YEC:

> "Q: So in my simplified terms, the N-1 is, I guess, a simple criteria, looks at the peak, looks at the worst-case outage that would happen on the system, it is quite simple from that perspective, but I think it is also probably quite pessimistic. The likelihood of that happening is probably quite slim. Is that fair?
>
> A: Right. As I said earlier, the deterministic criterion is a hard criterion. It does not have any edge to it with respect to the likelihood of the event occurring. It simply says this condition -- can the system withstand this particular condition at the time of system peak?
>
> Q: So would you say that the LOLE criteria is more realistic?
>
> A: No, it is more responsive, and it gives you an entirely different perception of your system. And we believe, in this particular case, ***that accepting the two then provides protection with respect to the vulnerability of Whitehorse to that***

> ***particular event, and also provides an overall assessment of the system, the second part of course coming from the LOLE."*** [Emphasis added]

Finally, YEC provided evidence from Mr. Morrison under redirect examination that the risks related to winter electrical supply on WAF would be exceedingly high without an N-1 criteria, starting from discussion about the specific January 29, 2006 outage (transcript page 538 line 13 to page 541 line 8):

> "Q: And how long was it before you were able to get the Aishihik line fully back on line. When I say "fully back on line" ... not derated in any manner. How long did that take?
>
> A: Not derated?
>
> Q: Right.
>
> A: Three weeks.
>
> Q: So it took three weeks in order for the Aishihik line to fully come back on line to the system?
>
> A: That is correct.
>
> Q: And during that time, from the time you brought the power back on, 12 or 13 hours after the outage was out, to February 21st, you were able to provide power to all of your customers?
>
> A: Yes, and that is what I meant when I said that it took us 12 or 13 hours to get the power back on. We had some customers on in about three to four hours. It took us 12 or 13 hours to get all of the customers back onto the system.
>
> Q: Now, sir, I want to -- given that, I want to give you an assumption, and I would like you to comment on it. I want you to assume that the N-1 criteria is not approved, and you have a similar outage, at a similar time, on the Aishihik line, and that the Mirrlees, which are scheduled for retirement, are retired, and no new capacity is added to the system. How long would it have been before you would have been able to restore power, in such a circumstance, to everybody on the system?
>
> A: Well, Madam Chair, let me start by saying that if the N-1 criteria isn't there, and we have -- and we lose essentially 11.4 megawatts of diesel because we retire them and we don't replace them, first of all, I don't know how I am going to sleep at night in the winter, because the -- if the N-1 scenario happens, it, essentially, originally means we cannot fully supply the load, period. We would be 11 – let me go back and try to do pretty simple math.
>
> We have 87 megawatts of capacity on the WAF grid, fully supplied. If we lose the Aishihik line again, either the plant or the line, in totality, we are down to 57 megawatts. In recent years, so within this last couple of years, we have been in the 56 megawatt peak range. Well, that leaves us one extra megawatt, given that everything works, always. But you know, so we are -- basically, we are right at the margin.

> So if you are asking me how we deal with the scenario of losing a further 11 megawatts, until such time as that Aishihik line could come up, or could be brought back on in full service, we would be 11 megawatts, 10 or 11 megawatts short, and would be in a series -- and very significant rolling black-outs in the system for the entire period of time that line was down. We would not be able to supply. And that would be a serious issue, from our perspective. It would be an almost impossible situation, over time, in terms of trying to operate that system over any length of time.
>
> I think, you know, from our perspective, given that we have lost a line a couple of times, and you know you could take -- you could take the position that, well, you know, if you play the odds, well, we have already lost it, so you know, are chances smaller that you will lose it again? Having gone through that scenario, I do not think it would be -- it certainly would not be responsible, on our part, to put ourselves in that position, and I think it would be a horrendously difficult situation for us all to face every winter, knowing that we did not have enough capacity to meet that inevitability."

In summary, the evidence on this matter is clear – from both the considered opinion of Dr. Billinton's expertise and the corporate position of Mr. Morrison regarding responsible Corporate behaviour with respect to operation of the power system, the lack of an N-1 criteria would not be appropriate, would not be consistent with other jurisdictions including NWT and utilities throughout North America, and would not allow YEC to provide reliable electric power generation to meet the load forecast requirements.

A separate topic addressed under cross-examination by Board Counsel indicated that two criteria may be redundant in that only one criteria (the N-1) is the driving factor throughout the period of the Resource Plan (transcript page 362 line 20 - page 368 line 13). This matter is addressed in particular by Mr. Bowman at page 366 line 6 – page 368 line 13, noting that neither criteria dominates under all circumstances reviewed in the Plan. In particular, in the event of even modest mine load (solely Minto and Carmacks Copper) the LOLE criteria becomes the dominant consideration, as well as in the event an Aishihik 2nd transmission line is constructed, as follows:

> "I just wanted to help, what may be -- and may not be -- but may be a misunderstanding in the premise for the question. The graph you have turned to is the simple WAF base case forecast, and that is at page 4-9. And it would show that in a base case forecast, where you have no industrial loads, the N-1 would, indeed, be the driving factor throughout the period of the Plan. There is one key difference, though, between the LOLE and the N-1 as proposed, as reviewed by Yukon Energy, and as ultimately adopted, which is the LOLE criteria reflects an overall balance on the system to ensure reliable power can be provided throughout the year.
>
> The N-1 is an emergency or back-up criteria related to those loads that do not have their own back-up. The practical difference is that, when you are calculating the LOLE, you include the load of industrial customers. When you are calculating the N-1, you do not include the load of industrial customers.
>
> So if you look at that same graph, the same model, but four pages further in the document at page 4-12, it will show the same graph but with those lines in the case where we have added Minto and Carmacks Copper mine, and you will see that, in that

situation, within the 20-Year Resource Planning period (sorry, this is page 4-12), within the Resource Planning period, the LOLE becomes the dominant criteria driving the system during the life of that mine. So it is a relevant criteria for the period of the 20-Year Resource Plan.

And the other relevant consideration is that two criteria, together, are intended to be robust and not have to be redesigned should the system topology change. The concept of an N-1 criteria relating to those loads who do not have their own backup, and an LOLE relating to the entire system loads, is intended to be durable whether we build a second line or not, or whether other interconnections occur.

And to the extent that people would want to turn to it, the graphs start to get a little bit more complicated, but at page 4-36, the situation with an Aishihik second transmission line is shown. And in that case, you can still apply the same two criteria. You can still apply them during the planning period, and they are relevant to the overall plan, and they would show the N-1 criteria dropping quite dramatically because you are no longer exposed to the 30 megawatt risk. The LOLE criteria drops somewhat for the same reason, but not nearly as much as the N-1. So, in fact, the LOLE is slightly above the N-1 criteria there, and that is before any mines are added. Were there to be a second line and mines, the LOLE would be quite a dominant driving characteristic. So the idea of proposing two during the 20-year period was that they would be robust and they would be able to deal with these different contingencies."

4.3 DATA LIMITATIONS AND THE USE OF CANADIAN ELECTRICITY ASSOCIATION NATIONAL DATA

Yukon Energy has not collected reliability data on its generation and transmission units in the form required to allow for determination of average forced outage rates or unavailability consistent with industry-standard definitions. This is described in some detail at YUB-YEC-1-1 Attachment 1 (the Billinton report) at page 54 (Exhibit B-6) and at YUB-YEC-2-3 (Exhibit B-12).

As a proxy, Dr. Billinton has recommended the use of Canadian Electricity Association (CEA) Equipment Reliability Information System (ERIS) data collected from utilities across Canada. Three key points were noted in evidence related to this issue:

1. **YEC is now collecting its own data.** In response to YUB-YEC-2-3, YEC indicates that older data has been compiled into a single database, procedures have now been put in place and data collection is beginning under consistent definitions.

2. **The CEA data is reasonable.** In the report prepared by Dr. Billinton (provided in YUB-YEC-1-1 Attachment 1, Exhibit B-6) the use of CEA data is specifically addressed at page 32 as follows:

   "The CEA-ERIS outage database includes a large quantity of similar equipment data collected over a rolling five-year period. These data, therefore, provide useful representative data for reliability studies, and are often used when actual data are unavailable or inadequate to assess the performance of the equipment."

YEC further notes in response to interrogatory YUB-YEC-1-6(a) (Exhibit B-6) with respect to the Aishihik transmission line that:

> "As to the likelihood of an outage in future, the recorded YEC data is not considered a good representation of the reliability of this line, partially due to the relatively small sample set represented by the YEC data, and partially due to the inconsistent record availability. As a result, YEC has accepted the recommendations of Drs. Billinton and Karki to use the national averages for this type of transmission construction from the CEA-ERIS database."

3. **Even if YEC had its own data, which would be preferable, the CEA data has the benefit of a larger "sample set".** Dr. Billinton has indicated that compared to the relatively limited number of units and outages that will underlie YEC's own data today or into the future, the CEA data provides the benefit of a much larger sample of units, as follows:

> "In terms of the transmission line data, I may be wrong here, the CEA report, we produce an annual report, which we use five years rolling average. In connection with 138 kV wood pole H-frame lines, there's 93,000 kilometre years of data in that particular category. So there is a large population from which that statistic is drawn. From the hydro unit case, there's 175 units in Canada between -- let's see, in the size category up to 25 megawatts, and therefore there's a large number units in that particular pool. When you look at the number of units and the number of lines that YEC has, you basically have one or two lines, we might call it, 170 and 171, you have a certain number of kilometres. The population size is not great, and therefore, having confidence in the statistic requires you either have an awful lot of outages, or to collect it for a long time. And, therefore, I think the CEA data is very useful for that particular purpose. But going back to your original comment, you are correct. The best data you can have is your own data. And therefore I think you need to collect that data under consistent definitions." (transcript page 379 line 18 to page 380 line 15).

Yukon Energy will continue to collect the required data to allow it to develop a dataset for future analysis as a comparison to the CEA data. For the foreseeable future, however, YEC will continue to be required to use CEA data on the forced outage and unavailability rates on generation and transmission units.

4.4 PEAK PERIODS ONLY OCCURRING FOR A SHORT PART OF THE YEAR

Under cross-examination by Board Counsel, Yukon Energy was asked about the planning criteria (in particular the N-1) and its use of the single highest system peak, given that the system peak only occurs for a relatively few number of hours each year.

Yukon Energy's N-1 criteria considers the full forecast system peak, and ensures that the generation available if the Aishihik line were to be out of service is sufficient to supply that peak.

In response to suggestions that the N-1 criteria might be best aimed at supplying only some portion of the peak load (such as 0.9 times the forecast peak load) rather than the full load, Yukon Energy highlights the following evidence before the Board:

1. **In most systems, the peak only occurs for a short period of time, similar to Yukon:** This is noted by Dr. Billinton at transcript pages 369 lines 9-12. In this regard, there is nothing unique in the Yukon that would require the typical N-1 type criteria to have to be modified from practice on other jurisdictions.

2. **N-1 as applied in other jurisdictions, particularly areas governed by NERC, uses the single highest peak:** This is described by Dr. Billinton at transcript page 370 line 9-21.

3. **The N-1 is a deterministic criteria, and any peak "de-rating" would be mixing probabilistic concepts into a deterministic criteria:** Dr. Billinton notes this at pages 370 lines 1-8. Further, Attachment 2 to YUB-YEC-2-7 (Exhibit B-12) which is the NWT PUB decision in regards to the Yellowknife capacity planning criteria indicates that in NWT the peak load to be used in the N-1 formula is 105% of the forecast peak load to account for "a safety factor for load forecast uncertainty" (page 29) rather than any form of de-rating of the peak to 90%.

In summary, the evidence before the Board in this proceeding provides no basis for establishing an N-1 criteria at any level below the full forecast peak load level.

ATTACHMENT B

ATTACHMENT B: NON-INDUSTRIAL LOAD FORECASTS

1.0 OUTLINE OF THE FILED EVIDENCE

Yukon Energy's Resource Plan includes a non-industrial load forecast supported and confirmed by the evidence in this proceeding. In particular, this includes the following key information:

- **Resource Plan January filing (Exhibit B-1) (Pages 4-4 to 4-8):**
  - Summary of 4 load forecast scenarios reviewed by YEC, including the "base case" of 1.85% growth per year in non-industrial loads.
  - Major events, like closure of Faro mine, can lead to huge swings in population and loads (Yukon lost 10% of its population in years after Faro mine closed).
- **Key First Round IRs (Exhibit B-6):**
  - YUB-1-8: Supporting data from other Rate filings and Yukon Bureau of Statistics.
- **Key Second Round IRs (Exhibit B-12):**
  - UCG-2-43: Footnote 1: Proposals in this plan not hinge on load forecast scenarios.
  - YCS-2-F1: Potential for increased use of electric heating.
- **Relevant transcript sections:**
  - Page 52, line 3 to page 53, line 1: Presentation: Capacity requirements under the near-term load forecast scenarios reviewed in Resource Plan.
  - Page 164, line 24 to page 180, line 2: Recent experienced growth rates for wholesales to YECL.
  - Page 216, line 26 to page 221, line 8: describing Undertaking #1 detailing and updating wholesale load growth rates cited in the Resource Plan.
  - Page 221, line 7 to page 225, line 20: describing Undertaking #2 which reviews YECL's load forecasts from past years in comparison to actuals.
  - Page 318, line 13 to page 325, line 7: load trends in Whitehorse.
  - Page 532, line 1 to page 534, line 8: Relative unimportance of YEC's load forecast to projects proposed in Resource Plan.
- **Undertakings:**
  - Undertaking #1 (Exhibit B-18): provides detailed calculations of the growth rates used in YEC's evidence
  - Undertaking #2 (Exhibit B-19): YECL's 3-year forecasts provided to YEC over the last 4 years, and how they compare with actuals.

2.0 SUMMARY OF THE EVIDENCE

The Resource Plan sets out actions and projects Yukon Energy proposes to pursue in each of the near-term and longer-term scenarios to meet the forecast loads. As is typical practice in bulk power resource planning, Yukon Energy has developed a load forecast including alternative scenarios. The load forecast concepts are quite distinct as between the near-term and longer-term scenarios:

- ***For the near-term horizon,*** Yukon Energy sets out at Table 3.5 (page 3-24 of the Resource Plan, Exhibit B-1) the load carrying capability of the existing system, including the impact of retirements, under the new capacity criteria. Of note is that by 2012, after the planned retirement of all 3 Whitehorse Mirrlees units, the system would be able to carry a peak of only 44.3 MW. This is well below the N-1 peak load experienced today of 56.4 MW, even without any load growth. In short, the need for investment in near-term capacity projects is being driven primarily by factors outside of the load forecasts. This is further summarized at transcript page 532, line 1 to page 534, line 8 under re-direct examination, as follows:

  "Q: The first question I have, and I think Mr. Bowman would probably be the appropriate person, given the questioning that he received on the issue of forecasts, the forecast growth, and there was a number of questions from UCG's counsel, and also counsel for the Board, on this issue, and, at the end, you made a comment in response to a question, Mr. Bowman, something to the effect that the load forecast that's in here really does not have a material impact -- and those are my words, not yours -- on the projects that are being proposed here. Do you recall at least those questions that were asked in relation to that?

  A: Vaguely, yes.

  Q: I know that this was dealt with in the record, somewhere, in terms of forecast. Do you know what IR that was answered, that effectively dealt with that issue?

  A: If I understand the question, the issue is of the load forecast and the extent to which the load forecast is driving or is underlying the need for the projects in the Plan. We dealt with this, to some extent, in UCG Question Number 43. It is actually in a footnote. It is not the most fascinating thing to read on the fly, but I can summarize for you.

  Q: Would you do that, please.

  A: In the period of the Resource Plan, we are talking about facing a capacity shortfall, compared to the criteria that has now been adopted, and reflecting the retirement of the Mirrlees, of 18.7 megawatts. It is a number that has been used a number of times. That 18.7 is the number to 2012. Of that 18.7, far and away the driving factor is the adoption of the new capacity criteria and the retirement of the Mirrlees. The only component of that 18.7 that is related to differences in load forecasts between now and 2012, and the extent to which it is 2 versus 2 1/2 versus 1 1/2, is about somewhat less than 25 percent. So in other words, even under the low forecast scenarios, we are talking about shortfalls in the order of 15 megawatts; in other words, the entire fleet of Mirrlees that we are talking about. So this goes to my comment earlier, that in many cases, when you are sitting looking at a long-term Resource Plan, and people who follow the utility industry will know this in spades from the '70s and '80s and old NCPC plans, or Ontario Hydro, the Plan really hinges on what rate of growth are you going to assume. And if you have a high rate of growth, you get a completely different development scenario than if you have a low rate of growth. And people spend a lot of time debating that.

> In this Plan, it is not like that at all. Very little of what is in the Plan, particularly in the near-term projects, relates at all to debating those particular load forecasts."

In addition, two of the projects proposed over $3 million (the Carmacks-Stewart transmission line and the Aishihik 3rd turbine) are proposed based on the opportunities they provide to sell surplus hydro or provide better peaking capability and are similarly not related directly to non-industrial load growth.

- ***With respect to the longer-term***, these scenarios focus fundamentally on the potential for new as-yet-uncertain industrial customers, and no projects are proposed today. As such, nothing in the Resource Plan in regards to these scenarios hinges on the selection of a particular non-industrial load forecast.

Regardless as to the relative importance of the specific load forecast, YEC did provide detailed information and data in support of its forecasting approach. This includes cross-references to the long-term load forecasts of other Canadian utilities such as Manitoba Hydro and NS Power as well as the Yukon Bureau of Statistics (YUB-YEC-1-8, Exhibit B-6). YEC also provided updated detailed data in regards to experienced load growth on the WAF system, indicating that updating the Resource Plan figures to include more recent data since the Resource Plan was prepared would serve to slightly *increase* the Yukon Energy forecast, rather than decrease (Exhibit B-18 and transcript page 216, line 26 to page 221, line 8).

In regards to qualitative assessment of the trends in Whitehorse and the integrated systems, detailed testimony primarily by Mr. Morrison at page 318, line 9 to page 324, line 11 under cross-examination by Board Counsel, sets out the key support for the Whitehorse load forecast over the near-term periods (to 2012):

> "Q: I have a couple of areas I would like to follow up on that Mr. Buonaguro discussed with you, and then I will turn my attention to the planning criteria. First, with regard to the load forecasts, you have filed some information regarding the load forecasts, and the expected continued growth in the forecast. What I would like to know -- it appears to me, that over the past number of years, or in the recent past, there has been a fair bit of growth in Whitehorse in terms of commercial growth, and, specifically, I am thinking of the facilities that have been built for the Canada Games next year. There is, I believe, an athlete's village and the recreational complex, and there might be another facility as well. There are some of the big box stores, Wal-Mart, et cetera. And I understand that these new loads will, you know, provide some increase to your load forecast, but in terms of significant, new commercial growth like that coming on, do you expect that trend to continue?
>
> A: MR. MORRISON: I think, when we look at the load forecast, we expect the trend to continue for different reasons. We have gone through a period where we have seen some significant capital expenditure, which would be institutional; as you mentioned, the Canada Games facilities, those kind of things. We have also gone through a period where there was an increase in commercial development. I think if you look, you know -- if the weather wasn't quite as cold, and we all had an opportunity to get

out a little more, you would see, around Whitehorse, that there is a significant number of new, and significant for Whitehorse, you know, I preface my comments, but significant number of new condominium units being built, including, I mentioned earlier, this building behind us. I think there are two, at least two others. My understanding is they are all on electric heat.

Q: Go on.

A: I just have a couple more points. We have also not seen any of the real impact, yet, of the growth in resource development. So the current resource development growth has been in the exploration sector, and we have seen exploration spending, you know, expand quite a bit. And that certainly has added to the growth in Whitehorse. But we are about to see, at least one if not more, new mines come in, which then provides a steady base of employment and income that should add to the already existing growth in the commercial sectors here. There are a number of new buildings planned, from the commercial side of things, over the next several years as well, so there is further development still coming on stream in the area where Wal-Mart is, and a few of those new developments. So for the next several years, we see this growth continuing.

Q: With what you just mentioned about commercial growth that you are expecting in the area where Wal-Mart is, would you expect that it would be to the same magnitude as what has been seen in the past couple of years?

A: I am not certain that -- if you mean magnitude, I do not think that we will get very many more single developments the size of Wal-Mart. You know, the Canadian Tire development is bigger than Wal-Mart, and it is due to come on stream sometime next year, and I would think early next year, there is another large development down there. I think what it will turn to is more smaller developments. A lot of them, again, related to the internal economy. When we have the mine, and the salaries from the mine, and the suppliers of goods and services to the mine, those types of activities will create further employment, which will create further demand in the commercial sector. So our forecast is, in the next few years, that we see that trend continuing fairly strongly. All of it will depend on whether or not the resource development sector and/or other developments come along in behind the single mine that we now have.

Q: Okay. With respect to the residential growth that you mentioned, the new condo complex or complexes.

A: Yes.

Q: I would not expect -- and I think this is what you were getting at, is that that is not going to contribute a significant amount to the load growth. It is going to contribute to load growth, and it is going to, maybe partly, make up for, as a trade-off, some of the commercial growth that has been seen recently. Is that a fair assessment?

A: No. Not quite. I think what I was trying to say is that, on the commercial side of things, we will see more developments of a smaller size than we have in recent years, so not so much the Super Store, Wal-Mart size developments, but smaller businesses that will either be -- that are either existing and expanding, or coming in to provide goods and services, you know, in a competitive marketplace as

Whitehorse grows. And Whitehorse is growing, and has substantially, over the last few years. There is no immediate indicator, from our perspective, that there is a slowdown in government spending, which is a huge part of our economy; as a matter of fact, over the last few years, government spending has increased beyond what we would even have anticipated. So the City, as it grows, as a municipality, but the primary, you know, spender at the government level, is the territorial government. All of this creates the high level of activity that we have not seen, and we anticipate will continue to see for several years.

Q: So would I be fair to say, then, that it is the continued small commercial growth, residential growth, and that is going to, essentially, equal, continue the trend, that you have seen over the past few years?

A: I think it is going to -- it is going to at least equal the forecast that we have in the Plan. The difficulty I have with just saying yes to your answer, simply is that we are starting to see some really big spikes, and I think what we are looking at in the Plan is even some smaller levels of growth than what these actual spikes in the last couple of years are. And if this year is an example, given that we are going through a fairly continuing period of colder weather, our sales, again, are going to be -- they are going to be higher than we even forecast, again. And so I think when we come back to the 2.2 percent that we talked about earlier, and Patrick, you can certainly help me out on this, we are not anticipating -- you know, we are not forecasting 4 and 5 percent growth. You know, we are trying to keep our forecast to a reasonable level. So it is not the spikes that we see, but we think we are going to at least maintain the 2-plus percent growth.

A: MR. BOWMAN: I would just add that your comment was about continuation of trends seen in that Exhibit B-2, at page 24, that sets out the calculation of the growth rates that are used in the Plan. There are four different ways that it considers low to high scenarios. Both of the higher-than-medium scenarios are based on recent experience. Both of the lower-than-medium scenarios are based on looking solely at general demographic trends, and the Plan takes something in the middle. So, if anything, the Plan is not reflecting continuation of what is seen at 1.85 percent, it is below what has recently been seen, as we reviewed this morning, which has been more in the 2.2, 2.3 percentage range. So, from that perspective, it is not sort of hinging on continuation of what we have seen."

3.0 ISSUES RAISED IN OTHER EVIDENCE

No party has called evidence to contrast with any aspect of Yukon Energy's near-term load forecast scenarios.

The only presentation made to the Board in this proceeding, by Mr. John Maissan, did not specifically address the issue of YEC's load forecasts. However, Mr. Maissan did, at page 416, line 24 to page 417, line 15, indicate a substantial concern regarding electric heating installations. Such increased use of electric heat is not presumed in Yukon Energy's load forecasts. In short, Mr. Maissan's presentation in effect highlights the extent to which the load forecasts may understate the potential for growth in electric loads were electric heating to become a major new factor in Yukon.

4.0 ISSUES RAISED UNDER CROSS-EXAMINATION

Outside of basic review of Yukon Energy's analysis, there was only one key issue noted by YEC arising from cross-examination. This related to data arising from analysis of 10-year growth trends. This matter is addressed below.

4.1 10-YEAR LOAD GROWTH TRENDS

Under cross-examination by UCG Counsel at transcript pages 164, line 24 to page 172, line 19, Yukon Energy discussed the long-term wholesale load changes in Yukon covering an approximately 10 year period from 1995 to 2005. UCG Counsel submitted that wholesale loads had grown on 0.23% per year over that period.

Yukon Energy dealt with this issue under cross-examination, as well as pages 4-5 to 4-6 of the main Resource Plan (Exhibit B-1) noting that after the Faro mine closed for the final time in 1998, nearly 10% of the Yukon's population left the Territory. In short, there is no surprise that over a period starting with the Faro mine in operation and ending with a period when the mine is closed will show little to no growth, if not declines. However, this is only relevant to planning the extent that there is a risk that another Faro mine will close in the next 10 years compared to today – which is simply incorrect reasoning (given there are no major industrial customers operating in Yukon today).

The issue raised is quite valid in regards to Resource Planning in a context where major downside "market risks" exists, such as they did in Yukon during the 1992 capital resource plan review, as discussed at pages 1-9 to 1-10 of the main Resource Plan (Exhibit B-1). In today's context however, UCG's cross examination if anything only serves to highlight the upside risks today that new mines coming on line (such as Minto) will accelerate load growth compared to recent experience, in the exact opposite way loads reacted to a major mine closure (although likely at a smaller magnitude given the relative size of the mines in question).

5.0 OTHER ISSUES NOTED AT HEARING

Although not provided as evidence to the Board, YECL did note comments in their September 25, 2006 withdrawal letter (Exhibit C1-5) that the YEC load forecast was "overly optimistic". YECL suggested four factors essentially related to 2 main topics:

- **The unsustainability of current load growth patterns:** YECL indicated that the load forecast was overly optimistic as it failed to recognize "the impact big box stores will have on the local marketplace" and "the unsustainability of continued Federal Government contributions for local recreation infrastructure". Yukon Energy dealt with this issue extensive in the evidence, and highlights three key points in this regard:
    1. The Resource Plan forecasts are not based solely on recent experience. As shown in Exhibit B-18, the most recent 5 year loads reflect annual growth of 2.3%, whereas the Resource Plan uses 1.85%.

2. To the extent the cited factors were driving growth in recent years (big box stores and federal government contributions), if anything growth trends for the next 5 years are more likely to be based on increased industrial activity as is now being seen with the Minto mine and others, as well as continued (although potentially much lower than recent experience) residential and commercial development. In addition, nearly 1/3 of Yukon Energy's growth rates relate solely to the trends expected by major Canadian utilities with respect to the increase in usage-per-customer, reflecting in part adoption of new technologies (0.5% per year) even if there is no growth in customer numbers.
3. Neither Yukon Energy nor apparently YECL have incorporated into their numbers risks related to increased use of electric heat, as noted above or by YCS at transcript page 88 lines 8 to 21.

- **Potential Future Rate Changes (primarily residential):** YECL indicated that Yukon Energy has not taken into account "the impact of impending rate rebalancing directives to improve revenue to cost ratios" and "the impact of the end of the Yukon Government's Rate Stabilization Fund on March 31, 2007 or some other date". The point raised, without being specifically stated by YECL, effectively posits that power bills in Yukon are set to increase dramatically in the very near future and this will have some form of muting effect on load growth. Three preliminary points are noted by Yukon Energy:
  1. Yukon Energy would note there is no evidence before the Board in regards to the potential termination versus extension of the Rate Stabilization Fund at March 31, 2007 or any other date. The OIC enabling the fund has expired at least twice since it was created in 1998 and in each instance the fund has been continued basically status quo. Yukon Energy has no basis to know when or if this fund will be ended within the Resource Planning period.
  2. The two references relate primarily or exclusively to residential customers (there is no outstanding rebalancing directives for General Service or industrial customers, and the RSF only applies to General Service customers in a very limited way). It is commonly understood in the electrical utility field that residential loads are typically not particularly sensitive to price (loads are "inelastic"). Beyond a simple assertion of a relationship in this area, YECL has provided no evidence to the Board to suggest for some reason that this type of well understood inelastic relationship would not apply to Yukon residential customers.
  3. The support Yukon Energy has provided for its load forecasts are based on simple demographic data, as well as reasonable expectations about such matters as the impact of increasing mining activity on Yukon. YECL's suppositions in no way refute this Yukon Energy position, which is supported by the evidence.

At a high level, Yukon Energy also notes that the evidence in this proceeding clearly demonstrates that YECL has consistently underestimated forecast load developments over any multi-year duration. For example, Exhibit B-19 indicates that starting in 2003, YECL forecast wholesale growth over the following 3 years totaling 0.9% (forecast 225.7 GW.h in 2006 compared to 223.7 GW.h in 2003), while actual loads instead grew by about 7.5% over this same period (247.1 GW.h in 2006 compared to 230.0 GW.h in

2003). The same trend exists with the YECL forecasts for each of the other years presented in that Exhibit.

In summary, the matters raised by YECL with respect to load forecasts, along with having no evidentiary support in this proceeding, do not ultimately challenge or undermine any of the relevant and evidence-based support Yukon Energy has provided for its load forecasts.

ATTACHMENT C

ATTACHMENT C: FINAL COMPILATION – PROPOSED ACTIONS

Yukon Energy's Resource Plan (Exhibit B-1) provides in the front of the document a "summary of proposed actions". As a result of updates and progress since the Resource Plan was first prepared in January 2006, this summary is now dated. This Attachment sets out an updated current version of Yukon Energy's proposed actions that incorporates all project related updates addressed to date.

PROPOSED NEAR TERM ACTIONS

Three separate major investments are proposed for Yukon Energy generation and transmission commitment before 2009 with anticipated costs of $3 million or more. These proposed major projects will address near term requirements and opportunities to 2012 and together will provide over 24 MW of new WAF firm winter capacity by 2012 (i.e., enough new firm capacity to meet WAF capacity shortfalls that would otherwise be expected by 2012 of 18.7 MW under the Base Case forecast and 21.5 MW under the Base Case forecasts plus the Minto and Carmacks Copper mine loads). The major proposed projects are reviewed below, along with contingency provisions and other proposed actions before 2012:

1. **Aishihik 3rd Turbine Project:** This project, which was initially reviewed in the 1992 YUB Resource Plan hearing, will provide 7 MW of added peaking capability[1] and about 5.4 GW.h/yr of long-term average hydro energy supply at the existing Aishihik generation station at a capital cost of about $7.155 million (2005$). Under Base Case loads without any new industrial developments, this project is expected to be economic within the planning period to 2025 based solely on its diesel operating cost saving benefits for the WAF grid, including displacement of peaking and then baseload diesel as WAF loads increase. Yukon Territorial Water Board and environmental approvals for the project were received in the new Aishihik Water Licence.

   Accordingly, this project will proceed with final planning activities to enable a final decision during 2007 to start construction for in-service by October 2009 and YEC will confirm economic assessment prior to 2007 decision to start construction. In the event loads or expected peaking diesel requirements are below that forecast in the Resource Plan, the final decision to start construction is proposed to be deferred until late 2009 for in-service in 2011 or 2012.

2. **Carmacks-Stewart Transmission Line Project:** This project will fully interconnect the MD and WAF grids as well as facilitate WAF transmission access to potential new mine loads at Minto and Carmacks Copper, providing 5.6 MW of additional firm near term capacity and 15 GW.h/year of additional near term energy for WAF2. Development of this project, with a

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

[2] Added capacity and energy supplied to WAF by this interconnection are subject to MD loads, and will decline as MD loads increase. Reopening of the UKHM mine or other new industrial developments on MD, for example, would reduce MD surplus capacity and hydro energy available to WAF. In contrast, potential additional enhancements at the existing Mayo hydro facility or other new

mid-point estimated cost of about $35.4 million (2005$), is subject to ensuring no adverse impact on ratepayers from project development. Planning activities are underway so as to enable a decision to proceed with construction of Stage 1, to start as soon in fall 2007 as all approvals are received, in order to achieve in-service in quarter 3 of 2008. The timing of development of Stage 2 (Pelly Crossing to Stewart Crossing) is affected by a number of risk factors, including confirmation of Carmacks Copper mine operation and grid connection, the absence of UKHM reopening on MD, and continuing likely need for some levels of YTG funding to ensure no adverse rate impacts from Stage 2 development.

3. **Mirrlees Life Extension Project**: The Mirrlees Life Extension Project will proceed during 2007-2010 to provide an additional 19 MW of firm WAF winter capacity at a cost of up to $8.7 million (2005$).
    a) **First Mirrlees unit in service by October 2007:** By the summer of 2006 planning work and commitments for construction/implementation will begin on the first Mirrlees unit (5 MW, located at Faro, or comparable used units of equivalent capacity) in order that in-service will occur before October 2007.
    b) **Three Whitehorse Mirrlees units by October 2008, 2009 and 2010**: Life Extension for the other three Mirrlees units will proceed thereafter for expected in-service in 2008, 2009 and 2010, subject to review of the experience gained from Life Extension of the first unit.

4. **If further capacity is required, implement diesel replacement/expansion and/or other project options as appropriate:** If further capacity is required, the key near term choice is between increasing Whitehorse Diesel installed capacity (involves relocating the three EMD units (7.8 MW) and replacement with up to 16 MW of new diesel engine generation (2 - 8 MW units) or potentially a dual fuel combustion turbine), the Aishihik 2nd Transmission Line (providing 22 MW under N-1 criteria and about 14.4 MW with LOLE criteria)[3] and the potential ability to secure 6.4 MW of high speed diesel units from the Minto mine after connection.

    In the event these contingency options are required, assessment will focus on the expected cost advantages of the Minto units compared to the Aishihik-related option, which provides overall system benefits but is not expected to be the most flexible or lowest cost option.

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

generation opportunities in the MD area could enhance overall WAF/MD power supply in the event of Carmacks-Stewart Transmission line development.

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

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

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

PROPOSED ACTIONS RELATING TO INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

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

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

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

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

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should then proceed to commit the Aishihik 3rd Turbine and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments.
  - If not already committed, Aishihik Diversions and Atlin Storage should then be advanced to Level 2 studies, including system-wide water and load dispatch modeling, to quantify the energy benefits under this scenario.

   – Ongoing assessment of the Southern Lakes should be completed to identify additional water control or small hydro opportunities to enhance Whitehorse Rapids output.

- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission line is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility, including enhanced peaking capability.

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

- **Other activities re: DSM:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused primarily on reduction of system peak demand.

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

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

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

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should proceed to commit the Aishihik 3rd Turbine and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments (see proposals for Scenario 1).

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

- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility (including any feasible enhanced peaking capability).

- **New hydro site development:** If industrial and overall load development commitment on WAF before 2016 is such that WAF baseload diesel generation energy of more than 10 MW (70 GW.h/year) is then required through to at least 2025, and there is no clear indication of more major industrial development scenarios establishing new WAF industrial loads in excess of about 20 MW (about 125 GW.h/year) emerging during the 20 year planning period and extending beyond 2025, planning activities should then be carried out to enable commitment of a small hydro site development (7-10 MW, about 50 GW.h/year[5]) able to provide diesel displacing energy to WAF.
  - New hydro options focused on Yukon-based projects, if available, would be the preference.
  - However, given limited attractive projects in this size range identified in Yukon to date, further Level 1 and 2 activity should be undertaken if timing permits in areas within 50 km of existing 138 kV WAF transmission focused initially on scans of the various inventory studies completed by NCPC or others.
  - Sites in BC, including Moon Lake and Tutshi6, should have Level 2 studies updated in preparation for this possible load scenario, particularly focusing on the costs and risks associated with interprovincial licencing requirements and water rentals. Level 3 studies should then proceed if warranted.

- **Coal supply possibilities:** In the event that the loads of this scale develop and coal also becomes available from developed Yukon sources, coal generation technology should be reviewed in the event that timing permits to determine the potential for an economic and environmentally sound coal development at sizes below 20 MW, sized as appropriate to fit the industrial loads being developed at that time.

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

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

[5] Present estimates of the costs are $50-$100 million generation capital cost (2005$) with potential generation planning costs of $5-$10 million prior to a decision to proceed with construction.
[6] No further work should proceed on Surprise Lake so long as the community continues its plans to develop micro-hydro at the site.

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

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

- **Load uncertainties and low probabilities today:** The industrial loads required to reach the above levels at this time involve significant uncertainties and low probabilities.

- **New medium scale hydro site development (20-30 MW, 130-150 GW.h/year):** The development of generation and transmission to serve these loads, based on currently identified potential hydro sites (Primrose and Finlayson), would involve substantial generation capital costs ($179-$191 million (2005$)), excluding transmission, as well as very large planning costs (about $20 million) prior to a decision to proceed with construction. Such costs are likely at or beyond the limits of YEC's current financial capabilities and involve material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line.

- **Coal supply thermal generation possibilities:** Coal resource options of this scale could involve far less capital than comparable new hydro sites, provided that coal supply as such was otherwise available from developed Yukon sources. The scale at 20 MW (144 GW.h/year[7]), however, is still very small for coal thermal technology and would require careful Level 2 and 3 screening and feasibility assessments to confirm its potential feasibility.

For potential generation projects related to the above scales, it is not apparent today that there is sufficient likelihood of this major development scenario arising to justify major investment at this time in planning and feasibility studies for medium new hydro or small coal plants. Accordingly, no specific planning activities are recommended at this time.

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

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

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

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

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

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

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

Proposed “Pre-commitment” activities

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

- **Monitoring of Industrial load developments:** Yukon Energy will continue to monitor closely potential load development and related spin-off residential and commercial impacts, including necessary discussions with mineral exploration companies active in Yukon, key officials in Yukon government working with mines and other industrial developments and relevant industry associations. Separately, YEC will maintain ongoing monitoring of potential Alaska Highway pipeline developments and factors that may impact electrical loads in Yukon (including potential for electrical compression).

- **Southern Lakes hydrology assessments:** Continued assessment and studies of the hydrology of the southern lakes area, including identification of potential for water control structures to enhance output of Whitehorse Rapids, as well as potential hydro generation sites.

- **Other existing hydro facility enhancements:** Continued focus on projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases, Mayo. This includes full Level 3 and 4 studies on the Aishihik 3rd turbine and updating Level 2 studies on Aishihik diversions. Where suitable, activities should be carried out in conjunction with other normal Supply Side Enhancement planning by Yukon Energy, such as re-runnering.

- **Level 1 and 2 assessments to identify preferred 5-30 MW scale Yukon hydro sites**: There is an option to invest in further surveying the potential of other Yukon based hydro generation sites to try to identify good sites in the 5-10 MW range (within about 50 km of existing high voltage transmission) and to advance credible candidates in the 5-30 MW range through Level 2 assessments (including ongoing monitoring of hydrology) in order to identify more clearly preferred sites to develop for possible loads within this range. However, this activity is costly and may require assessment of a number of sites. No activities in this regard are recommended today; however, in the event that at least one large industrial load (such as Red Mountain or Division Mountain) proceeds to advanced licencing and likely commitment stages, it is proposed that this initial work should proceed quickly to determine if the sites identified to date are indeed the best candidates or if there are other Yukon-based sites that should be seriously considered, and to identify specific projects for Level 3 feasibility assessments.

- **Ongoing monitoring of hydrology**: Active hydrology monitoring will proceed where feasible for all hydro sites likely to be serious candidates for future development within the 20 year planning period. The monitoring may be periodic (seasonal flow information, current cost of $1,000 per year per site) up to a full-time recording station (at a current cost of $30,000 (initial costs) plus ongoing costs of between $10,000 to $15,000 per year).